UTIER MTA Exhibit 1

NEPR-AP-2019-0001
In Re: Request for Approval of Amended and Restated Power Purchase and Operating Agreement with EcoEléctrica and Natural Gas Sale and Purchase Agreement with Naturgy

> NEPR-AP-2019-0001

Expediente: NEPR-AP-2019-0001

In Re: Request for Approval of Amended and Restated Power Purchase and Operating Agreement with EcoEléctrica and Natural Gas Sale and Purchase Agreement with Naturgy
Documentos Publicados: 30

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Documentos	Fecha	Descargar
Petition of EcoEléctrica, LP. to Intervene Asunto: Petition to Intervene	16/diciembre/2019	Documento
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PREPA-Request for Reconsideration of Resolution and Order on Denial Without Prejudice of Approval of Amended and Restated Power Purchase and Operating Agreement with EcoEléctrica and Natural Gas Sale and Purchase Agreement with Naturgy Asunto: Resolution and Order on PREPA's Request for Approval of Amended and Restated Power Purchase Agreement with EcoEléctrica and Natural Gas Sale and Purchase Agreement with Naturgy; Request for Confidential Treatment	09/diciembre/2019	Documento
Resolution and Order Asunto: Resolution and Order on the Puerto Rico Electric Power Authority's Request for Approval of Amended and Restated Power Purchase Agreement with EcoEléctrica and Natural Gas Sale and Purchase Agreement with Naturgy; Request for Confidential Treatment.	27/noviembre/2019	Documento

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Anterior 1 Siguiente

UTIER MTA Exhibit 2

NEPR

NEPR-MI-2020-0005
In Re: Instrucciones Temporeras sobre Procedimientos Administrativos y Presentación de Documentos

> NEPR-MI-2020-0005

Expediente: NEPR-MI-2020-0005

In Re: Instrucciones Temporeras sobre Procedimientos Administrativos y Presentación de Documentos
Documentos Publicados: 6

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Orden Asunto: Recalendarización de Procedimientos Administrativos y Métodos de Presentación de Documentos	25/mayo/2020	Documento
Orden Asunto: Procedimiento para la Celebración de Ciertos Trámites Procesales de Forma Remota	20/mayo/2020	Documento
Orden Asunto: Recalendarización de Procedimientos Administrativos y Métodos de Presentación de Documentos.	03/mayo/2020	Documento
Orden Asunto: Recalendarización de Procedimientos Administrativos y Métodos de Presentación de Documentos.	13/abril/2020	Documento

Documentos	Fecha	Descargar
Orden Asunto: Recalendarización de Procedimientos Administrativos y Métodos de Presentación de Documentos	31/marzo/2020	Documento
Orden Asunto: Recalendarización de Procedimientos Administrativos y Métodos de Presentación de Documentos	16/marzo/2020	Documento

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PREPA Ex. 1.0

Siemens PTI Report Number: RPT-015-19

Puerto Rico Integrated Resource Plan 2018-2019

Draft for the Review of the Puerto Rico Energy Bureau

Prepared for

Puerto Rico Electric Power Authority

Submitted by:
Siemens Industry

Rev. [2]
6/7/2019

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v16

Revision History

Date	Rev.	Description
01/21/2019	0	Initial draft
02/12/2019	1	Second Draft with Implementation Plan and Caveats and limitations and other adjustments
06/07/2019	2	Third draft with responses to PREB Order.

Contents

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Part
1

Introduction and Summary of Conclusions

1.1 Introduction

Following the massive destruction resulting from hurricanes Irma and María in 2017, Puerto Rico faced the unprecedented challenge of rebuilding their electric power system. The hurricanes forced the Puerto Rico Electric Power Authority (PREPA) to rethink how its power supply and delivery infrastructure should be modified to ensure that the utility infrastructure was much better prepared for future weather events. The experience of these disasters has focused PREPA on the need to increase the resiliency and survivability of its systems, with due consideration to system hardening, distributed generation, decreased dependence on fuel oil, and increased reliance on renewable energy resources. Economics is not the only driver in PREPA's resource planning program. In addition, PREPA's current fiscal situation as a debtor under the Title III of the Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA) requires it to identify a roadmap for the electrical system infrastructure that will support its path to comply with sound financial utility practices.

The development of an Integrated Resource Plan (IRP) is essential in developing a plan that would realize these goals. PREPA is required, under Puerto Rico Act 57 of May 27, 2014 (Act 57-2014), as amended, to prepare an IRP which shall consist of a detailed planning process considering all reasonable resources to satisfy the demand for electrical services over a twenty (20) year planning horizon, including resources related to energy supply and demand. In addition, the IRP shall consider resiliency, reliability, and stability of the power system, and be fully compliant with current and future environmental regulations.

This document and associated appendices present PREPA's 2019 IRP, which provides the analysis and recommendations for PREPA's energy supply resources for a 20 year period (2019 to 2038). The parts and appendices of this document are intended to fulfill the requirements of the Puerto Rico Energy Bureau (PREB) Regulation 9021, Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority (IRP Regulation). The IRP was developed by Siemens Power Technology, Inc. (Siemens) using a rigorous analytical process. The IRP analyses considered a large number of options and uncertainties, recognizing formal and informal input from PREPA and a large number of stakeholders.

The IRP recommendations are fully aligned with the five key pillars adopted by the PREPA Governing Board in its Vision for the Future of Power in Puerto Rico that we summarize below (also see Exhibit 2-2):

1. **Customer-Centric**: The IRP includes costumer participation via energy efficiency, customer side energy resources and demand response with a predominant role in

the supply and consumption matrix of Puerto Rico, and empowering customers to participate and take ownership on their energy security and affordability.

2. **Financial Viability**: Within the requirements of resiliency and reliability, the plan minimizes the cost of supply and drastically reduces the dependence on imported fuels and the associated volatility; thus, supporting affordable rates that promote financial viability at both sides of the meter.

3. **Reliable and Resilient**: The IRP is centered on the concept of MiniGrids, defined as zones of resiliency into which the system can be segregated during and after a major weather event ensuring that the load can be served using local resources. In addition, MiniGrids must support effectively preparing, managing and timely recovery from such event.

4. **Model of Sustainability**: The IRP's implementation will transition the Puerto Rico electric system from one centered on fossil fuels to one in which renewable resources play a central, if not, the predominant role. The IRP's implementation will drastically reduce emissions, increase the penetration of renewable generation, achieve compliance with all current regulations, and position Puerto Rico for future regulations.

5. **Economic Growth Engine**: The distributed nature of the new generation resources that will have to be developed, the high levels of customer participation on the energy production and the overall reduction in the system cost are expected to result in employment opportunities and economic growth for Puerto Rico. The IRP will support a reliable and economic system that will attract economic development in Puerto Rico.

The 2019 IRP is not a classical IRP designed to identify the least cost approach to address the expected gap between future load growth and resources while maintaining a desired Planning Reserve Margin (PRM). Rather, this plan must satisfy the five pillars stated above for a system with declining load. The load served by the PREPA is projected to significantly decline over the course of this IRP's planning horizon due to a combination of expected base load reduction (driven by negative population and economic forecasts), large energy efficiency gains, and demand side resources. Instead of new resources to meet load growth, this IRP is designed to address the following needs:

a) Address the impacts of an aging generation fleet that burns costly liquid fuels (mostly heavy fuel oil), that does not meet environmental regulations (e.g. Mercury and Air Toxics Standards "MATS"), has poor reliability, and is inflexible, which limits the incorporation of renewable resources.

b) Achieve a reduction of cost of supply by incorporating renewable resources which will provide a permanent reduction in expensive and volatile fuel costs, trading this off by effective capital investments.

c) Achieve compliance with the Renewable Portfolio Standard (RPS) mandate and exceed the mandate because the renewable cost benefits alone justify greater levels of penetration.

d) Shift from centralized generation located in the south of the island to more decentralized generation resources distributed across the island.

Should the declining load forecast not materialize, resources must be available to serve load in a resilient and reliable manner. This load growth uncertainty requires additional planning and optionality, which is manifest in the Action Plan and its associated recommendations. Load growth is a very real concern to PREPA, and growth at this moment is highly uncertain and could go from negative to positive should federal monies stimulate the economy, out-migration reverse, or industrial and tourism industries increase. Developing new generation resources take time, in the order of several years, and PREPA is designing a plan with the necessary flexibly to initiate development opportunities that can be implemented should the forecast prove to be incorrect

In developing this IRP, Siemens worked with PREPA and the PREB to identify five Scenarios deemed worthy of analysis:

Scenario 1 - No new natural gas (gas) delivery infrastructure added combined with expected (base case) cost and availability of renewable generation.

Scenario 2 - Gas delivery is made available only in the north combined with expected (base case) cost and availability of renewable generation (this Scenario was dropped after the first screening).

Scenario 3 - Gas is made available at multiple, new LNG terminals (north, east and west locations) combined with further reduction in the cost of renewable and higher renewable availability.

Scenario 4 - Gas is made available at multiple, new LNG terminals (north, east and west locations) combined with expected (base case) cost of renewable and availability.

Scenario 5 - Similar to Scenario 4, but with the Aguirre Offshore Gas Port as an option, larger combined cycle units and centralized Strategy 1, as described below.

In addition to the five Scenarios above, a sixth Scenario, the Energy System Modernization (ESM) plan was considered. The ESM is essentially a derivative of Scenario 4 with the stated purpose to expedite the implementation of a resilient resource plan utilizing procurement options presented by the Public Private Partnership Authority, identify the pricing structure necessary to retain existing natural-gas fired generation in the south, consider locational alternatives for new large scale CCGTs, and ensure reliable capacity in the San Juan area. The ESM Plan contains provisions for development activities that allow PREPA to install new economic and resilient generation resources should actual load be higher than the IRP's forecast. The ESM was analyzed and compared on an equal footing with the other Scenarios described above. Please see document titled "Considerations on the ESM Plan" included in the Resource Side Work Papers for further details on this plan.

The Scenarios were combined with one or more of the three different resource strategies:

Strategy 1 - Reflects a traditional, centralized energy program with generation resources predominately located at a few centralized locations emphasizing reliability and economic metrics.

Strategy 2 - Reflects a system of more distributed, flexible generation, emphasizing resiliency and closer proximity of generation sources to the customer. The strategy incorporates micro or MiniGrids and hardening of existing PREPA infrastructure. In this strategy, most of the load is supplied from local

supply resources that can be isolated from the remainder of the grid during a major event, but still supply all or a portion of the nearby load.

Strategy 3 - Reflects a hybrid of the first two strategies that embodies a combination of the benefits of Strategy 1 and Strategy 2. In this strategy, economies of scale are considered, which results in some of the load potentially served, under normal conditions, from remote resources. During a major event, the potential for greater levels of rotating load shed in this strategy is greater than with Strategy 2 but should also result in lower operating costs.

Siemens combined Scenarios and strategies to define the structure under which candidate portfolios of resources were assessed. To these combinations of Scenarios and strategies, Siemens added assessment of high, base and low load forecasts and several sensitivities were considered (e.g. high gas prices, high/low cost of renewable, etc.). Part 5 - Resource Needs Assessment, of this document, provides further details on the complete range of analysis.

In the development of the IRP, over 78 Long-Term Capacity Expansion (LTCE) plans were investigated to assess plausible options and numerous uncertainties, taking into account stakeholder input. These points were critical for the final product and included multiple aspects, for example: a) the timing of investments in traditional thermal generation units, b) practical limits to the ability of PREPA to effectively interconnect additional battery energy storage and renewables generation, c) uncertainty associated with fuel price forecasts and infrastructure options, d) uncertainty associated with the customer demand forecast, and d) assessment of resource candidates provided by PREPA's management and the Puerto Rico Public-Private Partnership Authority (P3). As detailed in Part 7 – Assumptions and Forecasts, this effort resulted in the identification of second set of 34 LTCE plans that were assessed and presented in the first draft of this document. Subsequent to the PREB review and to account for the provisions of Act 17-2019, a final set of 35 Cases (not all of which implied an LTCE run) were created and used to identify the recommended resource plan with a primary focus on the next 5 years, while also considering the long-term planning horizon of 20 years. Part 8 – Resource Plan Development of this IRP provides the details of assessment and inputs of the resources. A summary of the main resource additions of the 35 Cases are provided in Exhibit 1-6.

The next section provides a summary of Siemens conclusions and recommendations based on the consideration of the broad array of Scenarios and all strategies represented in the 35 Cases and identification of common elements among them to define the minimum regret or no regret decisions (i.e., the decision that would provide the best possible solution over the broadest range of potential future conditions). Siemens has also prepared the transmission expansion plans associated with the generation resource options, which is summarized in Appendix 1 – Transmission and Distribution Planning.

This IRP is a recommended plan for PREPA and Puerto Rico. The IRP does not address the details of procurement, interconnection, ownership, rate structures, nor the issues associated with PREPA's debt or privatization plans. It should also be noted that federal funding for certain projects could alter the IRP and the associated Action Plan significantly. All of these other important issues will need to be addressed in other processes and venues, and later combined with this IRP to develop a complete roadmap for Puerto Rico's power system.

1.2 Summary of Conclusions and Recommendations

The action plans for the first five years of this IRP are the most important because they lay the foundation for the future of Puerto Rico's electrical system and create options for PREPA as future uncertainties are ultimately resolved. The foundational recommendations of this IRP provide for system resilience, generation optionality (near-term development activities), lower rates, partnerships with the customers, and improved sustainability. The foundational recommendations of this IRP are: a) integrating the maximum amount of renewable generation that is practical to interconnect in the first four years of the planning period, b) adding distributed resources and hardening the transmission and distribution grid so that it can be segregated into eight largely self-sufficient electric islands (MiniGrids) c) increasing energy efficiency and demand response and d) retiring obsolete oil fired units and modernizing the generation fleet with dual fuel (LNG) gas turbines. These changes are essential to mitigate, manage and enable timely recovery from future major storms, while shifting the existing generation fleet from largely heavy fuel oil and distillate fuels to renewables and cleaner natural gas.

The review of the options revealed two resource plans that were deemed both low cost and most practicable, the ESM and the Scenario 4 Strategy 2 (S4S2) plan. Under the Base conditions and High Load conditions, these two plans differed in by less than 1% or under $100 million, as measured by net present value of cash flows (NPV) for the 20 year study period. However, the S4S2 cost benefits increase in the Low case as compared to the ESM plan, thus this plan is more sensitive do drops in the load than the S4S2B. The NPV results of the two plans under the three cases, base, high and low, are shown in the Exhibit below.

Exhibit 1-1: ESM and S4S2 NPV Results ($ million)

	S4S2	ESM	Difference	Difference
Base	$14,350	$14,431	($81)	-0.6%
High	$15,155	$15,255	($99)	-0.7%
Low	$12,866	$13,952	($1,086)	-8.4%

In addition, one significant difference between the ESM case and the S4S2 is that in the former, the EcoEléctrica plant is assumed to remain in service for the planning period with renegotiated and extended contract. As discussed in section 4.1.1.5, Siemens adjusted the fixed costs of EcoEléctrica to those that were expected to result in breakeven with a new CCGT installed at Costa Sur (we assumed a 53% reduction on fixed costs after 2022). However, the actual LTCE results for S4S2 indicated that the 53% reduction in cost was insufficient for the LTCE to select the renegotiated EcoEléctrica option over a new CCGT built at Costa Sur. It was subsequently estimated that a 60% reduction would have been sufficient for the LTCE to select the renegotiated EcoEléctrica option over a new CCGT at Costa Sur. However given that the actual outcomes of the negotiations are a function of multiple factors including the certainty of PPA costs versus the inherent risks of developing a new project, instead of re-running the LTCE, we maintained the original 53% reduction to the fixed costs and ran a sensitivity (S9) for Scenario 4 where the EcoEléctrica (S4S2S9) remains in service, similar to the ESM case. As can be observed in the Exhibit below, substituting the discounted EcoEléctrica resource in S4S2S9, in lieu of the new CCGT at Costa Sure results in a plan that is slightly more expensive than the ESM (0.3% difference) with the same assumptions for EcoEléctrica. EcoEléctrica is an efficient resource with a proven high availability and existing LNG fuel infrastructure. The successful renegotiation of

its contract provides for a more certain outcome than the development of new generation in the same region of Puerto Rico.

Exhibit 1-2: ESM and S4S2S9B NPV Results ($ million)

	S4S2S9	ESM	Difference	Difference
Base	$14,480	$14,431	$49	0.3%

The S4S2 (and S4S2S9) plan calls for higher level of renewable generation addition and less natural gas fired generation than the ESM plan. As shown in the Exhibit below, the RPS results for the two plans are within 1% under the Base assumptions for the terminal year of the study, 2038. However, the RPS results for the Low and High assumptions are mixed with S4S2 having the higher renewable penetration with the Low assumptions and ESM having a higher level of renewables under the High assumptions.

Exhibit 1-3: Summary ESM and S4S2 RPS compliance for Year 2038

	S4S2	ESM	Difference
Base	68%	67%	1%
High	60%	53%	7%
Low	77%	54%	23%

While the RPS is a good indication of the renewable contribution in a given year, a better indication is the cumulative renewable energy contribution for all years. As shown in the Exhibit below, S4S2 has greater cumulative renewable energy for 2019 to 2038 for both the Base and Low assumptions. This higher renewable contribution results from the S4S2 case adding 240 MW of additional solar PV by 2038 (i.e., a total of 2820 MW for S4S2 base case versus 2580 MW for the ESM base case)

Exhibit 1-4: Cumulative Renewable Energy for 2019 to 2038 for ESM and S4S2 (TWh)

	S4S2	ESM	Difference
Base	94	91	3%
High	93	89	4%
Low	86	72	19%

With respect of the NPV of Deemed Energy Not Served with MiniGrid Operation for the Base and High assumptions, see Exhibit below, the plans are very similar. This is a measure of the value of energy that would remain unserved during the islanded operation with MiniGrids

Exhibit 1-5: ESM and S4S2 NPV Results for Deemed Energy Not Served During MiniGrid Operation ($ million)

	S4S2	ESM	S4S2S9	Difference
Base	$247	$267	$268	$1
High	$319	$392		
Low	$198	$202		

While the ESM and S4S2 plans had a number of identical elements, they also contained important differences. In addition to the larger additions of solar PV in the S4S2, the other key differences between the two plans is the location of where the new large 302 MW CCGT additions are added and whether the existing Mayagüez peaking units are converted to natural gas. Both plans assume a 302 MW CCGT will be added to the Palo Seco plant in 2025. The key differences in the natural gas generation additions are shown in the Exhibit below.

Exhibit 1-6: Key Difference in ESM and S4S2 and S4S2S9 Natural Gas Generation

	S4S2	S4S2S9	ESM
302 MW CCGT at Costa Sur 2025	Added assuming EcoEléctrica cannot be renegotiated	Assumes EcoEléctrica is renegotiated in lieu of CCGT addition	Assumes EcoEléctrica is renegotiated in lieu of CCGT addition
302 MW CCGT at Yabucoa 2025 with ship-based LNG delivery infrastructure	Not Added	Not Added	Added
200 MW Mayagüez Peaker Conversion with ship-based LNG delivery infrastructure	Not Converted	Not Converted	Converted
23 MW Mobile Peaking Units	16 units added	16 units added	18 units added

Both the S4S2 and ESM plans present an aggressive addition of solar PV, BESS and natural gas generation and infrastructure. Execution of either plan will necessitate successful completion of a complex web of permitting, vendor negotiations, contracting and construction activities. In addition, how the PREPA customer load evolves presents one of the greatest uncertainties that could impact these plans. Economic stimuli associated with federal monies, improved electrical reliability, and overall infrastructure improvements could favor higher load growth that requires additional contingency planning. Likewise, if energy efficiency gains or customer provided distributed generation do not materialize at the levels modeled, future load could be higher than forecast.

Taking all these factors into consideration, Siemens recommends that PREPA proceed with the execution of the ESM plan with reassessment of the ESM assumptions and project progress in two to three years' time - near the completion of recommended development and permitting activities. The ESM plan provides the best overall combination of practicality, low costs, high renewable energy contribution and improved resource contingency planning and resiliency.

In order to minimize the potential adverse impacts of the uncertainties, Siemens recommends the ESM plan be implemented while preserving the ability shift to the S4S2 or S4S2S9 plans should the future customer load or project development progress indicate these options are more favorable than the ESM. While implementing the ESM, PREPA should closely follow the behavior of key indicators that will affect the pace of implementation of the selected plan. An example of these key indicators is the forecasted customer load, (including the provisions for energy efficiency, demand side resources and economic grow). Other important factors that may impact the planned implementation include the ability to construct the solar PV at the forecasted prices and pace, and the implementation of the CCGT at Palo Seco, including the land based LNG terminal and the pipeline to the plant.

To better position itself for these uncertainties, Siemens recommends that PREPA proceed with the preliminary permitting and planning activities for the Yabucoa CCGT and the Mayagüez Peaker conversion together with their associated ship-based LNG delivery infrastructure, in addition to the new CCGT at Cost Sur. The intent would be that, prior to making any large contractual commitments for equipment purchase or construction for these projects, PREPA would reassess which combination of these project provide best option for the PREPA system. ***Proceeding with only the preliminary permitting and planning activities for each of these project preserves PREPA's ability to select either the plan described by ESM, S4S2 or S4S2S9 depending on the future circumstances. Proceeding with the preliminary activities for these projects will provide PREPA approximately two years to three years to allow some of the uncertainties to be resolved and formulate a clearer understanding of the potential need for the projects.***

The following three subsections, 1.2.1 to 1.2.3, provide a summary of conclusions and recommendations associated with the recommended implementation of the ESM portfolio and the projects at Yabucoa and Mayagüez as a variation from ESM to S4S2.

1.2.1 Transforming the Grid Architecture and Supply with MiniGrids

Central to the IRP is developing the capability to segregate the system into eight MiniGrids to improve the system resiliency. The MiniGrids require the recommended generation and battery energy storage projects described below and the recommended transmission and distribution additions (mostly underground facilities) and hardening projects described in Appendix 1. The recommended MiniGrids are designed to operate in grid-isolated mode following a major storm or other disruptive event. The MiniGrids are designed to ensure continued supply to critical loads (those loads most necessary for the safety and health) and provide timely recovery of the priority loads (those required to regain normalcy and restart the economy) and balance the loads within the MiniGrid. In addition to the MiniGrids, smaller microgrids have been identified for those areas that, due to geography and system topology, are likely to remain isolated for longer periods of time after a major event.

The business case for transforming the grid architecture is straightforward: it provides the least cost approach to achieve resilience against major hurricanes, meet and exceed compliance with the renewable portfolio standard, engage customers, and lower cost. Listed below are key recommendations to the grid transformation.

1. ***Maximize the rate of installation of solar photovoltaic (PV) generation for the first four years of the plan (2019 to 2022)***: Siemens recommends that PREPA issue request for proposals (RFPs) or other similar structures for solar PV (with associated BESS depending on pricing) in blocks of approximately 250 MW, with

goal of adding 1,380 MW over the first four years of the plan. Siemens recognizes implementation of large-scale PV and BESS resource is challenging with PREPA's current procurement and approval processes. This is the basis for an assumed limit for PV acquisition, however these constraint could be overcome either by the expanded capabilities of the new concessionaire or by streamlining and augmenting PREPA's procurement processes and internal capabilities[1]. The urgency of adding as much PV as practical is driven by the need to provide distributed power to critical and priority loads in the MiniGrids as soon as possible, the compelling economics of PV vs. existing fossil generation, and the pending expiration of the federal Investment tax credits.

2. ***Install 920 MW of Battery Energy Storage in the first four years of the plan:*** The amounts of battery energy storage are heavily correlated with the total amounts of PV to be installed and the local energy supply required for the MiniGrids into which the system is expected to segregate during major events.

   It is recommended that storage be added with PV additions, in blocks of 150 to 200 MW. Siemens also recommends that the RFPs for storage be combined with the RFPs for PV with the option of bidders providing either or both of these technologies. The combined RFPs give the developers the opportunity to co-locate the storage with PV and gain advantages of sharing plant equipment and interconnections and the possible extension of the investment tax credits to the storage costs.

3. ***Install new Gas Turbines (GTs) capable of burning containerized or truck delivered natural gas:*** The need to serve critical and priority loads within the MiniGrids resulted in the necessity to add 17 to 18 small GTs (23 MW each) at selected locations across the island. In addition, the new units will allow PREPA to retire the 18 existing old and unreliable Frame 5 GTs (21 MW each) The new GTs include 2 units located at Ponce East (Jobos), 4 units at Mayagüez North (Aguadilla), 5 units at Carolina (Daguao) - 5 units at Caguas (Yabucoa) and 2 units at Cayey. Siemens found the costs of these small GTs was significantly less than the economic costs to the Puerto Rico economy should another large hurricane strike Puerto Rico and the MiniGrids were forced to operate in isolated mode for a month and did not have sufficient resources to supply the critical and priority loads. In the assessment, Siemens included all the resources available to the MiniGrids during grid isolated operations including the thermal resources, PV, storage and GTs. These small GTs should be placed in service as soon as practical, as they provide a material improvement to the island's preparation for the next major storm and can be rapidly installed with a concerted effort to expeditiously seek regulatory authorizations and permits (2021 is assumed as the earliest commercial operation date).

4. ***Partner with Customers by Accelerating Energy Efficiency and Demand Response:*** Establish Energy Efficiency (EE) and Demand Response (DR) programs with the objective of reducing the demand in values approximating the 2% per year, (as defined in Part 3 – Load Forecast) Energy efficiency can add over 1,900 GWh of reduced demand by 2025. Demand response can add over 60 MW of flexibility to the

[1] In this filing of the IRP the limits on renewable adoption per year were increased significantly with respect of the limits in prior filing as per PREB Orders and the need to comply with Act 17-2019 RPS mandates.

system by 2025. The energy savings from both these programs are the least cost resources and may accelerate proportional to PREPA's customer engagement.

5. ***Enable Demand Response and Increased Distributed Energy Resources:*** Reinforce the distribution system and enable two-way flow of energy, provide voltage regulation and flicker control to facilitate the high penetration of distributed energy, as forecasted in this IRP (see Appendix 4 – Demand-Side Resources)

6. ***Convert Some Retired Plants to Synchronous Condensers:*** The system was found to be stable and have acceptable frequency response even with high levels of renewable generation online, thanks to the support from the additions of battery energy storage. However, studies also identified the need to convert some of the generators slated for retirement to synchronous condensers. Preliminary analyses indicate that Palo Seco Units 3&4, Aguirre 1 &2 and San Juan Units 7, 8, 9 and 10 are the minimum number of units that need to be converted over the life of the plan. However, Siemens recommends that a detailed study be conducted to determine the schedule, capacity, and costs of the synchronous condenser's conversions as well defined their expected technical performance in support of transient voltage recovery and stability. The stability study also identified the need to conduct a study to optimize the frequency response of existing and new resources (including storage) and the under frequency load shedding strategies.

1.2.2 New Infrastructure to Lower Rates and Achieve MATS Compliance:

PREPA must retire its obsolete oil fired units as soon as possible to lower rates and be in compliance with the Clean Air Act MATS provisions. In order to achieve these objectives, new LNG infrastructure will be needed to bring in lower cost and cleaner natural gas fuel for generation. Although three new natural gas terminals were found to be cost effective, the San Juan terminal is by far the most important given the concentration of load in the region and the importance of modernizing the generation fleet in order to increase system reliability and have sufficient flexibility to accommodate the large increase in renewable power.

7. ***Convert San Juan 5&6 Combined Cycle (CC) to burn natural gas***: This option is was contracted by PREPA with NFE using a ship-based liquefied natural gas (LNG) terminal and was adopted as a given in the formulation of all plans including Scenario 1 (no new gas), where only a sensitivity was ran to the eventuality that this project did not achieve completion. The construction of the NFE terminal is currently underway, and PREPA is proceeding with permitting activities to convert the two generating units. Note that initial runs of the LTCE early in the project had already identified this option as a least cost alternative (i.e. it was selected by the optimization process).

8. ***Develop a land-based LNG terminal in San Juan to supply a new combined cycle gas turbine (CCGT) at Palo Seco and the existing San Juan 5&6 CCGT***: This decision is selected in multiple LTCEs. However, the new Palo Seco CCGT is called for under the Base and High load growth assumptions but not under the Low load growth assumption for S4S2 or some of the strategies that allowed centralized generation (S1) . However, Siemens believes installing the land-based LNG terminal is prudent investment since it provides a cost effective solution across most assumption cases and provides critical support to the large population centers of San Juan and Bayamon.

The CCGT was limited to a smaller unit (F-Class representative unit) or about 302 MW, to limit the size of the largest unit in the system. Larger units H-Class of about 449 MW were selected by the LTCE runs if allowed. However, the CCGT size was limited to reduce the amount of spinning reserve generation that must be on line to respond to the potential trips of large generating units. This new CCGT should be in place as soon as practical (2025 was assumed in this study). Therefore, development and permitting activities are recommended to begin as soon as practicable.

9. ***Install a CCGT at Costa Sur Steam Plant or extend a renegotiated contract with EcoEléctrica:*** Under most cases and all S4S2 cases, EcoEléctrica is replaced by a 302 MW CCGT after the contract expires in 2022, unless the contract with EcoEléctrica is renegotiated to significantly reduce the fixed payments and the plant is allowed to cycle frequently. A fifty three (53%) reduction in fixed payments from 2022 onward was modeled, but it did not prevent the LTCE from retiring the plant. Further estimation identified that a 60% reduction would be necessary for breakeven under base load forecast and the forecasted balance of the generation fleet. The analysis assumes the new CCGT can be built in 2025 and to avoid uncertainties with respect of the price of fuel, it was evaluated as if it would receive the gas from a new Ship-Based LNG at Costa Sur, priced identically as the Ship-Based LNG at Yabucoa. This is la modeling conservative assumption to set a price cap, because the existing LNG infrastructure would be contracted to serve any new generation resources. Should EcoEléctrica be successfully renegotiated with lower fixed charges and significant term extension, this new CCGT at Costa Sur would likely not be needed and would mitigate risks associated with project development and permitting.

1.2.3 Additions to Preserve Options and Hedge Uncertainties

Siemens' IRP recommendations recognize that there are significant uncertainties in the future related to potential load deterioration, the relative cost trajectory of renewables and storage compared to gas, and the political environment for developing new LNG infrastructure. There is a potential that an unforeseen issue may prevent or significantly delay some of the planned solar PV and/or gas fueled generation additions described above. Given the long lead times, it is prudent to start the process for siting and permitting now and make the final decisions for equipment and construction commitments as future events reveal themselves.

10. ***Proceed with Preliminary Actives for Ship-Based LNG Terminal and Gas Generation at Mayagüez:*** Proceed with the preliminary permitting and engineering to support developing a new LNG import terminal at Mayagüez to supply the existing 4x50 aeroderivative gas turbines (Aeros) installed at Mayagüez that may be converted to natural gas. The recommendation is to advance the development of the ship-based LNG with the view of converting the existing units to burn LNG. Proceeding with the preliminary permitting and engineering activities for the LNG terminal development will preserve the option of converting the Mayagüez aeroderivative generation (4x50 MW) to gas and potentially supply a new 302 MW CCGT as the site should the gas generation at other sites be stalled or other developments indicate the need for additional gas fueled resources. This project is one of the projects that was not included in the S4S2 or S4S2S9 plans and its need

should be reevaluated by PREPA, in two to three years, following development and permitting activities and prior to committing to equipment or construction contracts.

11. ***Proceed with Preliminary Actives for Ship-Based LNG Terminal and Gas Generation at Yabucoa:*** A new LNG terminal at Yabucoa to support a large CCGT (302 MW) is part of the least cost solution under the inability to develop a land-based LNG at San Juan and higher costs of renewable generation. This terminal is recommended as a hedge against the potential that neither of the other two LNG terminals (San Juan and Mayagüez) can be developed. In addition, as was observed in the ESM plan, if the LNG terminal and the 302 MW CCGT are developed at Yabucoa, the cost differential with the S4S2 that develops a CCGT at Costa Sur is minimal. This Yabucoa CCGT, when part of the plan, is selected in general by 2025 (i.e. as soon as possible). This project is also a project that was not included in the S4S2 or S4S2S9 plans and its need should also be reevaluated by PREPA, in two to three years, prior to committing to equipment or construction contracts. The location of the Yabucoa CCGT is viewed by PREPA as a key potential resource for an area that was severely impacted by the hurricanes of 2017.

As a consequence of the investment decisions above and the expected reduction in the load, accelerated by the assumed energy efficiency gains and the increased penetration of demand side resources, most of the existing generating fleet is recommended to be retired by 2025, with the exception of the CCGTs at San Juan and Aguirre and the GTs at Cambalache and Mayagüez. It must be stressed that these retirements can only be carried out when all the conditions leading to the recommendation are in place; in particular, the new supply resources are fully operational. Many of these forecast retirements, like Costa Sur 5 and 6, currently serve as key load and reliability resources, and PREPA will need to preserve operations and maintenance (O&M) programs to ensure their availability until these recommendations are in place. It is important that PREPA refrain from pulling back on O&M expenditures until new resource come on line to replace these important assets. Moreover, considering that the IRP's commissioning dates, formulated last year, are likely to slip in reality, it is not unrealistic to expect the retirement dates referenced in this document may also be correspondingly postponed.

1.2.4 Understanding the IRP as a Road Map

There are many uncertainties in Puerto Rico's and PREPA's future which can be change the trajectory of the IRP decisions over time. What is certain is the urgent need to rebuild the system based on a MiniGrid architecture as soon as possible, with the accompanying renewable energy, storage, microgrids, customer side resources, and modernization of selected generation facilities, so that critical and priority loads can be resiliently served in the event of hurricanes or major storms. These recommendations and associated costs are detailed in the Action Plan (Section 10). By taking these actions, Puerto Rico is laying the foundation for a cleaner and more resilient system that retains options to respond to different customer load and pricing conditions that may evolve in future years.

1.3 Summary of all cases analyzed

The recommendations above are based on the results of 35 final cases analyzed and discussed in detail in this report (see Section 8) and whose main characteristics and results are presented below.

Again, it must be stressed that the IRP identified economic retirements shown below are based on several prerequisite developments which include the forecasted reduction in load, assumed levels of reliability of existing fleet remaining online until their planned retirement and the timely commissioning of the new generation resources. The IRP commissioning dates formulated last year, are likely to slip and it is not unrealistic to expect the planned unit retirements to be correspondingly postponed. Moreover, the retirement of existing generating units should be only implemented after all these prerequisites have been met, particularly that all new resources are fully operational, and units planned for retirement are not required for reliable operation of the system.

Exhibit 1-7: Summary of Investment Decisions by Scenario, Strategy and Load Growth[2]

	Large & Medium CCGTs and Peakers							Renewable and Storage				
Case ID	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peaker Conversion	Other	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)	Customer Owned Generation 2038 (MW)
S1S2B	–	EcoEléctrica Instead	✔	–	–	–	504	2,580	1,280	2,700	1,720	1,176
S1S2H	–	EcoEléctrica Instead	✔	–	–	Costa Sur 5 to 2034	325	2,820	1,360	3,180	1,840	1,176
S1S2L	–	EcoEléctrica Instead	✔	–	–	–	325	2,340	1,240	2,340	1,800	1,176
S1S3B	–	EcoEléctrica Instead	✔	–	–	–	513	2,580	1,280	2,580	1,840	1,176
S1S2S1B	–	EcoEléctrica Instead	✔	–	–	–	504	2,580	1,280	2,700	1,720	1,176
S1S2S5B	–	EcoEléctrica Instead	✔	–	–	–	504	2,580	1,280	2,700	1,720	1,176
S1S2S6B	–	EcoEléctrica Instead	✔	–	–	–	504	2,580	1,280	2,700	1,720	1,176
S1S2S7B	–	EcoEléctrica Instead	–	–	–	Costa Sur 5 to 2036	507	2,880	1,280	3,240	1,760	1,176
S1S1B	–	EcoEléctrica Instead	✔	–	–	Costa Sur 5&6 to 2037 & 2031	301.6	2,520	1,240	2,520	2,080	1,176
S3S2B	–	✔	✔	–	–	–	348	2,820	1,320	4,140	3,000	1,176
S3S2H	–	✔	✔	–	–	–	364	3,300	1,680	4,560	2,600	1,176
S3S2L	–	–	✔	–	–	–	389	3,000	1,600	4,080	2,520	1,176
S3S3B	–	✔	✔	–	–	–	371	2,820	1,280	4,140	2,280	1,176
S3S2S5B	–	✔	✔	–	–	–	348	2,820	1,280	4,140	2,280	1,176
S3S2S8B	–	✔	✔	–	–	–	348	2,820	1,280	4,140	2,280	1,176
S4S2B	✔	✔	✔	–	–	–	371	2,220	1,320	2,820	1,640	1,176

[2] See Part 5 – Resource Needs Assessment for a detailed description of the various Scenarios.

	Large & Medium CCGTs and Peakers							Renewable and Storage				
Case ID	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peaker Conversion	Other	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)	Customer Owned Generation 2038 (MW)
S4S2H	✔	✔	✔	–	–	–	394	2,460	940	2,520	980	1,176
S4S2L	–	✔	✔	–	–	–	434	2,100	960	2,520	1,020	1,176
S4S2S9B	✔	EcoEléctrica Instead	✔	–	–	–	348	2,220	1,320	2,820	1,640	1,176
S4S3B	2027	✔	✔	–	–	–	394	2,580	1,320	2,820	1,320	1,176
S4S2S1B	✔	✔	✔	–	–	–	371	2,220	1,320	2,820	1,640	1,176
S4S2S4B	–	✔	✔	–	–	–	371	2,580	1,320	3,060	1,640	1,176
S4S2S5B	✔	✔	✔	–	–	–	371	2,220	1,320	2,820	1,640	1,176
S4S2S6B	✔	✔	✔	–	–	–	371	2,220	1,320	2,820	1,640	1,176
S4S1B	–	–	✔	2028	–	F-Class at Mayaguez 2025	348	2,700	1,240	2,700	1,640	1,176
S5S1B	–	369 MW (2025&2028)	✔	–	–	–	371	2,580	1,200	2,580	1,480	1,176
S5S1S5B	–	369 MW (2025&2028)	✔	–	–	–	371	2,580	1,200	2,580	1,480	1,176
S5S1S1B	–	369 MW (2025&2028)	✔	–	–	–	371	2,580	1,200	2,580	1,480	1,176
S5S1S6B	–	369 MW (2025&2028)	✔	–	–	–	371	2,580	1,200	2,580	1,480	1,176
ESM	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2,580	1,640	1,176
ESM High	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,340	1,040	2,460	1,040	1,176
ESM Low	✔	EcoEléctrica Instead	✔	✔	✔	–	421	1,920	1,040	1,980	1,040	1,176
ESMS1B	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2,580	1,640	1,176
ESMS6B	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2,580	1,640	1,176
ESMS5B	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2,580	1,640	1,176

Green	Strong no regret with no variation among cases that support decision being made
Light green	Decision common to multiple cases / little variation between scenarios that allow the decision to be taken
Yellow	Decision common to few scenarios that allow the decision to be taken
Orange	Decision common to one scenario, PV / BESS: outlier or close follow up required.

Source Workpaper: Summary PREPA IRP Cases-06032019_v7.xlsx

Exhibit 1-8: Summary of Retirements by Scenario, Strategy and Load Growth[3]

	Large Thermal Retirements (last year in service shown)								
Case ID	AES 1 & 2	Aguirre Steam 1 & 2	Aguirre CC 1 & 2	Costa Sur 5 & 6	EcoEléctrica	Palo Seco 3 & 4	San Juan 5 & 6	San Juan 5 & 6 Conv	San Juan 7 & 8
S1S2B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2019 2 - 2020	5 - 2020 6 - 2022	Not Retired	3 - 2021 4 - 2023	5 - 2019 6 - 2019	6 - 2033	7 - 2021 8 - 2023
S1S2H	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2020 2 - 2020	5 - 2034 6 - 2020	Not Retired	3 - 2022 4 - 2023	5 - 2019 6 - 2019	6 - 2035	7 - 2023 8 - 2023
S1S2L	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2020 2 - 2021	5 - 2020 6 - 2020	Not Retired	3 - 2023 4 - 2021	5 - 2019 6 - 2019	5 - 2037 6 - 2030	7 - 2021 8 - 2023
S1S3B	1 - 2027 2 - 2027	1 - 2020 2 - 2020	1 - 2019 2 - 2020	5 - 2019 6 - 2021	Not Retired	3 - 2022 4 - 2023	5 - 2019 6 - 2019	5 - 2037 6 - 2031	7 - 2021 8 - 2023
S1S2S1B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2019 2 - 2020	5 - 2020 6 - 2022	Not Retired	3 - 2021 4 - 2023	5 - 2019 6 - 2019	6 - 2033	7 - 2021 8 - 2023
S1S2S5B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2019 2 - 2020	5 - 2020 6 - 2022	Not Retired	3 - 2021 4 - 2023	5 - 2019 6 - 2019	6 - 2033	7 - 2021 8 - 2023
S1S2S6B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2019 2 - 2020	5 - 2020 6 - 2022	Not Retired	3 - 2021 4 - 2023	5 - 2019 6 - 2019	6 - 2033	7 - 2021 8 - 2023
S1S2S7B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2020 2 - 2020	5 - 2036 6 - 2021	Not Retired	3 - 2022 4 - 2023	5 - 2023 6 - 2037	N/A	7 - 2022 8 - 2021
S1S1B	1 - 2027 2 - 2027	1 - 2019 2 - 2020	1 - 2021 2 - 2020	5 - 2037 6 - 2031	Not Retired	3 - 2019 4 - 2019	5 - 2019 6 - 2019	5 - 2036 6 - 2035	7 - 2019 8 - 2019
S3S2B	1 - 2027 2 - 2027	1 - 2019 2 - 2023	1 - 2020 2 - 2020	5 - 2021 6 - 2019	2024	3 - 2021 4 - 2023	5 - 2034 6 - 2020	5 - 2033 6 - 2030	7 - 2023 8 - 2020
S3S2H	1 - 2027 2 - 2027	1 - 2020 2 - 2020	1 - 2019 2 - 2019	5 - 2021 6 - 2021	2024	3 - 2022 4 - 2023	5 - 2021 6 - 2023	5 - 2033 6 - 2029	7 - 2023 8 - 2020

[3] See Part 5 – Resource Needs Assessment for a detailed description of the various Scenarios.

	Large Thermal Retirements (last year in service shown)								
Case ID	AES 1 & 2	Aguirre Steam 1 & 2	Aguirre CC 1 & 2	Costa Sur 5 & 6	EcoEléctrica	Palo Seco 3 & 4	San Juan 5 & 6	San Juan 5 & 6 Conv	San Juan 7 & 8
S3S2L	1 - 2027 2 - 2027	1 - 2021 2 - 2021	1 - 2019 2 - 2019	5 - 2020 6 - 2020	2024	3 - 2023 4 - 2021	5 - 2019 6 - 2023	5 - 2032 6 - 2029	7 - 2019 8 - 2021
S3S3B	1 - 2027 2 - 2027	1 - 2021 2 - 2020	1 - 2019 2 - 2019	5 - 2020 6 - 2021	2024	3 - 2022 4 - 2023	5 - 2022 6 - 2023	5 - 2033 6 - 2030	7 - 2020 8 - 2019
S3S2S5B	1 - 2027 2 - 2027	1 - 2019 2 - 2023	1 - 2020 2 - 2020	5 - 2021 6 - 2019	2024	3 - 2021 4 - 2023	5 - 2034 6 - 2020	5 - 2033 6 - 2030	7 - 2023 8 - 2020
S3S2S8B	1 - 2027 2 - 2027	1 - 2019 2 - 2023	1 - 2020 2 - 2020	5 - 2021 6 - 2019	2024	3 - 2021 4 - 2023	5 - 2034 6 - 2020	5 - 2033 6 - 2030	7 - 2023 8 - 2020
S4S2B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2025	5 - 2020 6 - 2020	2024	3 - 2025 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S2H	1 - 2027 2 - 2027	1 - 2020 2 - 2019	1 - 2025	5 - 2029 6 - 2020	2024	3 - 2025 4 - 2025	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S2L	1 - 2027 2 - 2027	1 - 2020 2 - 2019	1 - 2025 2 - 2032	5 - 2019 6 - 2020	2024	3 - 2021 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S2S9B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2025	5 - 2020 6 - 2020	Not Retired	3 - 2025 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S3B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2029	5 - 2020 6 - 2020	2024	3 - 2022 4 - 2023	5 - 2019 6 - 2019	5 - 2036 6 - 2032	7 - 2021 8 - 2023
S4S2S1B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2025	5 - 2020 6 - 2020	2024	3 - 2025 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S2S4B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2033	5 - 2020 6 - 2024	2024	3 - 2021 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2019 8 - 2019
S4S2S5B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2025	5 - 2020 6 - 2020	2024	3 - 2025 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S2S6B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2025	5 - 2020 6 - 2020	2024	3 - 2025 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S1B	1 - 2027 2 - 2027	1 - 2020 2 - 2019	1 - 2032 2 - 2025	5 - 2022 6 - 2020	2024	3 - 2019 4 - 2019	5 - 2019 6 - 2019	5 - 2035 6 - 2030	7 - 2019 8 - 2019
S5S1B	1 - 2027 2 - 2027	1 - 2019 2 - 2020	1 - 2033 2 - 2025	5 - 2020 6 - 2019	2024	3 - 2023 4 - 2022	5 - 2019 6 - 2019	5 - 2031 6 - 2026	7 - 2023 8 - 2021

	Large Thermal Retirements (last year in service shown)								
Case ID	AES 1 & 2	Aguirre Steam 1 & 2	Aguirre CC 1 & 2	Costa Sur 5 & 6	EcoEléctrica	Palo Seco 3 & 4	San Juan 5 & 6	San Juan 5 & 6 Conv	San Juan 7 & 8
S5S1S5B	1 - 2027 2 - 2027	1 - 2019 2 - 2020	1 - 2033 2 - 2025	5 - 2020 6 - 2019	2024	3 - 2023 4 - 2022	5 - 2019 6 - 2019	5 - 2031 6 - 2026	7 - 2023 8 - 2021
S5S1S1B	1 - 2027 2 - 2027	1 - 2019 2 - 2020	1 - 2033 2 - 2025	5 - 2020 6 - 2019	2024	3 - 2023 4 - 2022	5 - 2019 6 - 2019	5 - 2031 6 - 2026	7 - 2023 8 - 2021
S5S1S6B	1 - 2027 2 - 2027	1 - 2019 2 - 2020	1 - 2033 2 - 2025	5 - 2020 6 - 2019	2024	3 - 2023 4 - 2022	5 - 2019 6 - 2019	5 - 2031 6 - 2026	7 - 2023 8 - 2021
ESM	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2032	5 - 2020 6 - 2020	Not Retired	3 - 2025 4 - 2025	5 - 2019 6 - 2019	5 - 2035 6 - 2025	7 - 2023 8 - 2021
ESM High	1 - 2027 2 - 2027	1 - 2022 2 - 2019	1 - 2025 2 - 2025	5 - 2021 6 - 2020	Not Retired	3 - 2025 4 - 2021	5 - 2019 6 - 2019	5 - 2036 6 - 2025	7 - 2025 8 - 2022
ESM Low	1 - 2027 2 - 2027	1 - 2025 2 - 2025	1 - 2025 2 - 2028	5 - 2020 6 - 2020	Not Retired	3 - 2022 4 - 2025	5 - 2019 6 - 2019	5 - 2033 6 - 2025	7 - 2021 8 - 2025
ESMS1B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2032	5 - 2020 6 - 2020	Not Retired	3 - 2025 4 - 2025	5 - 2019 6 - 2019	5 - 2035 6 - 2025	7 - 2023 8 - 2021
ESMS6B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2032	5 - 2020 6 - 2020	Not Retired	3 - 2025 4 - 2025	5 - 2019 6 - 2019	5 - 2035 6 - 2025	7 - 2023 8 - 2021
ESMS5B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2032	5 - 2020 6 - 2020	Not Retired	3 - 2025 4 - 2025	5 - 2019 6 - 2019	5 - 2035 6 - 2025	7 - 2023 8 - 2021

Exhibit 1-9: Summary of Results by Scenario, Strategy and Load Growth

	Central Metrics							
Case ID	**NPV @ 9% 2019-2038 k$**	**Average 2019-2028 2018$/MWh**	**RPS 2038**	**NPV Deemed Energy Not Served k$ (1)**	**NPV + ENS k$**	**Lowest Reserve Margin**	**Emissions Reductions**	**Capital Investment Costs ($ Millions)**
S1S2B	14,773,629	102.2	54%	214,355	14,941,402	38%	96%	5,840
S1S2H	16,134,592	101.4	68%	392,504	16,527,096	36%	94%	5,857
S1S2L	13,535,576	101.3	68%	263,997	13,799,572	37%	99%	4,684
S1S3B	14,687,535	101.8	54%	485,666	15,173,201	33%	97%	5,560
S1S2S1B	14,449,784	100.1	54%	214,355	14,617,557	38%	96%	5,293
S1S2S5B	15,378,227	106.0	54%	214,355	15,546,000	38%	96%	5,840
S1S2S6B	16,018,738	110.2	54%	214,355	16,186,511	38%	96%	7,898
S1S2S7B	15,696,705	106.8	68%	422,543	16,119,248	44%	96%	6,606
S1S1B	14,366,811	98.4	68%	1,150,508	15,517,319	35%	96%	5,546
S3S2B	13,843,500	96.4	87%	205,871	14,049,371	48%	97%	8,474
S3S2H	15,191,427	97.3	68%	475,629	15,667,056	36%	92%	8,716
S3S2L	13,242,760	99.6	68%	303,185	13,545,945	47%	96%	7,851
S3S3B	14,627,724	99.8	68%	202,994	14,830,718	30%	92%	8,396
S3S2S5B	14,811,928	102.0	87%	205,871	15,017,799	48%	97%	8,474
S3S2S8B	14,357,561	99.2	87%	205,871	14,563,432	48%	97%	9,467
S4S2B	14,350,195	99.3	68%	247,445	14,597,640	42%	86%	6,595
S4S2H	15,155,383	96.7	60%	319,025	15,155,480	31%	81%	5,629
S4S2L	12,865,937	96.5	77%	198,037	12,866,033	33%	89%	5,321
S4S2S9B	14,480,364	99.6	68%	267,841	14,748,205	51%	94%	6,265

	Central Metrics							
Case ID	**NPV @ 9% 2019-2038 k$**	**Average 2019-2028 2018$/MWh**	**RPS 2038**	**NPV Deemed Energy Not Served k$ (1)**	**NPV + ENS k$**	**Lowest Reserve Margin**	**Emissions Reductions**	**Capital Investment Costs ($ Millions)**
S4S3B	14,416,274	99.9	54%	279,349	14,695,623	37%	82%	6,188
S4S2S1B	14,012,096	97.4	68%	247,445	14,259,541	42%	86%	5,961
S4S2S4B	14,466,325	100.9	65%	345,809	14,812,134	34%	84%	6,552
S4S2S5B	15,255,494	104.8	68%	247,445	15,502,939	42%	86%	6,595
S4S2S6B	15,565,108	106.7	68%	247,445	15,812,553	42%	86%	8,756
S4S1B	14,039,431	97.9	68%	1,108,890	15,148,321	47%	88%	6,674
S5S1B	14,122,690	98.4	67%	593,173	14,715,863	32%	87%	6,201
S5S1S5B	15,660,368	110.0	67%	593,173	16,253,541	32%	87%	6,201
S5S1S1B	13,813,169	96.4	67%	593,173	14,406,342	32%	87%	5,697
S5S1S6B	15,335,600	106.4	67%	593,173	15,928,773	32%	87%	8,165
ESM	14,431,214	99.0	67%	266,947	14,698,161	53%	88%	5,556
ESM High	15,254,859	97.0	53%	391,816	16,087,374	60%	91%	5,585
ESM Low	13,952,366	105.0	54%	202,453	14,154,819	58%	91%	4,779
ESMS1B	14,121,243	97.1	67%	266,947	14,121,340	53%	88%	5,556
ESMS6B	15,592,035	106.3	67%	266,947	15,592,141	53%	88%	5,556
ESMS5B	15,612,073	106.9	67%	266,947	15,612,180	53%	88%	5,556

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Part
2

Planning Environment

In this part Siemens documents the set of external factors that affect the environment under which PREPA is operating at the time of the IRP development. In addition to market conditions and stakeholders' input, it is important to consider the other key external factors that are in place, including applicable laws and regulations and conditions that have changed since the last IRP.

The description of this planning environment is a requirement of the IRP Regulation, which specifically requires the following:

- PREPA shall describe, at a minimum, the following factors: federal, state, or municipal standards and rules that impact the requirement for, or availability of, energy efficiency, renewable energy, fuel alternatives, or other resource requirements; and environmental standards and regulations that impact existing utility resources or resource choices at the present time and throughout the planning period.
- The Planning Environment part shall also include a discussion of substantial regulatory or legislative standards and rules that have changed since the approval of the most recent IRP.

Although there are numerous factors that have the potential to directly or indirectly impact the IRP, summarized herein are what have been identified to be the key factors warranting acknowledgement and documentation.

2.1 Environmental and Energy Standards and Regulations Applicable to PREPA

Puerto Rico is subject to most federal environmental standards applicable to energy generating facilities as well as state standards and regulations. A description of policies deemed as substantial to resource planning and how they are considered in the IRP analysis is included in Exhibit 2-1. These largely include the Environmental Protection Agency (EPA) federal air emission and water standards and Puerto Rico regulations governing energy efficiency, resource requirements, and environmental standards.

Exhibit 2-1. Environmental and Energy Standards Applicable to PREPA

Category	Law / Regulation	Summary
Federal Environmental Standards - EPA[4]	Mercury and Air Toxics Standard (MATS)	The MATS rule was finalized in December 2011 and requires facility specific emission reductions of mercury, acid gases, and particulate matter. This is a command-and-control type of regulation with no allowance trading. Several PREPA facilities remain out of compliance and are required to run for reliability purposes. The IRP will inform pathways to MATS compliance for these units.
	National Ambient Air Quality Standards (NAAQS)	EPA updated attainment designations for SO_2 based on detailed air quality monitoring in December 2017. The standard for SO_2 is 75 parts per billion. Puerto Rico must finalize a state implementation plan (SIP) by May 2019 addressing compliance for two areas designated as nonattainment. Emissions from all generating units will be modeled and reported in the IRP analysis. The IRP will inform the SIP as PREPA units currently represent the most significant emission sources in the areas in Puerto Rico designated as nonattainment.
	Greenhouse Gas Emission Standards	The New Source Performance Standards (NSPS) for Electric Utility Generating Units was finalized in August of 2015 and sets a rate limit of 1,000lbs of CO_2/MWh for combined cycle natural gas plants and a limit of 1,400lbs of CO_2/MWh for coal plants. Units emitting above these levels are not included as new generation options due to this rule and market conditions not supporting, for example, new build coal.
	Clean Power Plan (CPP)	The final CPP under Section 111(d) of the Clean Air Act was finalized in August 2015 and required state-level emission targets by 2030. Puerto Rico was not covered under the final rule. Due to legal challenges and additional review of this rule, it is anticipated that this rule will be withdrawn in its entirety. The IRP therefore is not modeling compliance with the CPP. CO_2 emissions are reported and are expected to show a significant decline.
Puerto Rico Energy Standards	Renewable Portfolio Standard (RPS)	Act 82 of July 19, 2010, as amended, defines specific requirements to promote energy diversification by creating an RPS (Renewable Portfolio Standard). This rule requires load serving entities to supply increasing shares of retail sales with qualified renewable and alternative sources at levels as amended by Act 17-2019. PREPA has not met RPS targets to date. The IRP will target compliance beginning in 2020, depending on feasibility, and maintain compliance for the balance of the study horizon. Sensitivities considering higher RPS targets are also modeled.
	Energy RELIEF Plan – Energy Efficiency	Act 57-2014, as amended, orders that within 5 years from enactment of Act 17-2019, at least 60 percent of the electricity generated in Puerto Rico from fossil fuels is generated in a highly efficient manner, as defined by the regulations approved by the PREB. Government energy savings mandates also established under this Act include a 40 percent reduction in energy consumption by state agencies, public corporations, and judicial branch buildings by promoting energy savings performance contracts (ESPCs) unless proven not cost effective. The Legislature must reduce its electrical energy consumption 12% by 2022, from a baseline of fiscal year 2012-2013. Municipalities must reduce electricity consumption by 5% annually for three years, or 15% in the first three years. Compliance was initially expected to begin in 2016 or 2017.

[4] These regulations and requirements are further detailed in the environmental section of the IRP found at the end of Part 4 – Existing Resources.

Category	Law / Regulation	Summary
		The State Office of Energy Policy now known as the Energy Public Policy Program or the Public Energy Policy Program of the Department of Economic Development and Commerce of Puerto Rico) will oversee the development and implementation of plans and programs to fulfill this law and publish semi-annual results from program evaluations. Act 57-2014, as amended, also mandates the benchmarking of energy use and monitoring of energy efficiency measures in all public buildings, including municipalities.
	Regulation on Microgrid Development	The PREB's final Microgrid Regulation of May 2018 sets the legal and regulatory framework required to promote and encourage the development of microgrid systems in Puerto Rico, enable customer choice and control over their electric service, increase system resiliency, foster energy efficiency and environmentally sustainable initiatives, and spur economic growth by creating a new and emerging market for microgrid services. It intends to promote the development of Microgrid systems by enabling their implementation through different business and operational models. The Final Microgrid Regulation recognizes three main types of microgrid systems: (i) Personal Microgrids; (ii) Cooperative Microgrids and (iii) Third-Party Microgrids. While supporting microgrids where operationally and economically beneficial, PREPA expressed concerns with the final Microgrid regulation adopted by PREB and may seek changes. In the context of long term resource planning, the IRP will identify microgrids that could be owned by the utility or private entities. Moreover, if during the development of the IRP plans for a privately owned microgrid become available, this could be incorporated as an option when assessing the coverage of the MiniGrids.

Source: various statutes and regulations referenced, Siemens

Additional detail on how these laws and regulations are accounted for in the IRP is included throughout the IRP report.

2.2 Laws and Regulations Changed Since Last IRP

Regulation on Integrated Resource Planning for the Puerto Rico Electric Power Authority (Regulation 9021)

The PREB adopted the Regulation 9021 on April 24, 2018. This regulation, referred to as the Regulation on Integrated Resource Plan for Puerto Rico Electric Power Authority, was enacted as required under the Act No. 83 of May 2, 1941, as amended, known as the Puerto Rico Electric Power Authority Act (Act 83 of 1941), and Act 57-2014, as amended, the Puerto Rico Energy Transformation and RELIEF Act. Regulation 9021 serves to make sure that the IRP is a useful tool to improve the system's reliability, resiliency, efficiency, and transparency, and offer electric power services at reasonable prices. Specifically, this regulation defines the required contents and organization of the IRP, the process with PREB, and performance metrics for PREPA following PREB's review and evaluation of the IRP.

Key parameters of the IRP are reflected including the defined 20-year planning period, the contents and organization of the IRP report and technical appendices, and sourcing requirements and documentation. As noted above, the requirement for documentation on the IRP planning environment is one of the required parts of the IRP. This IRP analysis also reflects the specific requirements outlined in Regulation 9021 regarding load forecasting, existing resources, resource needs determination including planning reserve margin, new

resource options including supply- and demand-side resources as well as distributed and storage resources.

To account for a range of future market conditions, Regulation 9021 specifies that the IRP shall consider multiple Scenarios that cover a reasonable range of possible outcomes for uncertain forecasts and that the IRP shall consider sufficient Scenarios to capture a wide range of possible risks and justify Scenarios included and those excluded. It is also required that a single reference case representing PREPA's best understanding of expected future conditions is included in the IRP. This Scenario is called the Base in this report.

The approach to analyze the resource options and tools used are also discussed in the requirements. Specifically, a capacity expansion model is required for the basis of the analysis. Further, sensitivity analysis of each resource plan is required. In this analysis, Siemens is using AURORAxmp® (by EPIS, now Energy Exemplar) as the long-term capacity expansion tool. Risk analysis is performed using Scenarios (high/low/base) and a number of sensitivities as discussed later in this report.

Finally, Regulation 9021 lays out the requirements for analysis of the transmission and distribution system. This will be addressed in the IRP analysis using AURORA nodal modeling, PSS®E transmission system studies and targeted distribution hardening distribution studies[5].

Regulation on Microgrid Development (Regulation 9028)

The PREB adopted the Regulation 9028 on May 18, 2018. This regulation, referred to as the Regulation on Microgrid Development, sets the legal and regulatory framework required to promote and encourage the development of microgrid systems in Puerto Rico, enable customer choice and control over their electric service, increase system resiliency, foster energy efficiency and environmentally sustainable initiatives, and spur economic growth by creating a new and emerging market for microgrid services. It intends to promote the development of Microgrid systems by enabling their implementation through different business and operational models. The Final Microgrid Regulation recognizes three main types of microgrid systems: (i) Personal Microgrids; (ii) Cooperative Microgrids and (iii) Third-Party Microgrids.

While supporting microgrids where operationally and economically beneficial, PREPA expressed concerns with Regulation 9028 adopted by PREB and may seek changes.

PREPA Revitalization Act, Act 4 of 2016

On February 17, 2016, the Governor signed into law the Puerto Rico Electric Power Revitalization Act, Act 4 of 2016. The law aimed to begin restructuring for PREPA's $9 billion debt as a means to start addressing the Commonwealth's $70 billion debt. Under the law, the PREPA Revitalization Corporation was created. This entity would issue new bonds in exchange for PREPA bonds under a new securitization that did not close. On July 30, 2018, the Governor of Puerto Rico and the federal Financial Oversight and Management Board (see below) announced a new agreement relating to restructuring certain of PREPA's debt,

5 These studies include those carried out by NYSSGC and ProsumerGrid for the Puerto Rico Grid Re-Design™ Study.

which may or may not implicate Act 4 in one or more respects. There have been subsequent developments. A restructuring, if consummated, could affect PREPA's cost of capital in the IRP.

Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA)

On June 30, 2016, President Obama signed into law, the federal Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA), which would create a structure for exercising federal oversight over the fiscal affairs of territories. PROMESA would establish a Financial Oversight and Management Board with broad powers of budgetary and financial control over Puerto Rico. PROMESA also would create procedures for adjusting debts accumulated by the Puerto Rico government and its instrumentalities and potentially for debts of other territories. Finally, PROMESA would expedite approvals of key energy projects and other "critical projects" in Puerto Rico. On July 2017, PREPA became a Debtor under the Title III process of PROMESA. The Fiscal Plan to be approved by the Financial Oversight and Management Board (FOMB) could affect PREPA's cost of capital in the IRP. On the other hand, the results of the IRP, especially the infrastructure investments, could affect PREPA's Fiscal Plan and its debt restructuring.

Ley para Transformar el Sistema Eléctrico de Puerto Rico (Law to Transform the Electric System of Puerto Rico), Act 120-2018

On June 20, 2018, the Law to Transform the Electric System of Puerto Rico was approved for the purpose of authorizing the legal framework required for the sale, disposition or transfer of assets, operations, functions, and services of PREPA. In general, this act provides the legal framework for the privatization process of PREPA, by means of public private partnerships (PPPs) transactions, among others. Act 120-2018 also establishes the necessary safeguards to ensure a fair and transparent process and amends the Act 29-2009, as amended, known as the Public Private Partnerships Law. Transactions like generation assets sales and other assets PPPs could affect PREPA's cost of capital in the IRP.

Act 17-2019, the Puerto Rico Energy Public Policy Act

On April 11, 2019, the Governor of Puerto Rico signed into law the Puerto Rico Energy Public Policy Act. The Act addresses the energy public policy of Puerto Rico, privatization, other subjects, and amends Act 83 of 1941, Act 57-2014, and Act 82-2010, among others.

2.3 Solar and Energy Storage Cost Decline

Due to technology improvements, growing economies of scale, and technology maturation, costs for solar energy and battery storage have declined rapidly in recent years. This is a trend that many anticipate will continue in the coming years, particularly for larger, utility-scale solar installations that are generally seen as less mature relative to solar installations at or on residential and commercial facilities. The NREL[6] Annual Technology Baseline (ATB) 2018 anticipates utility solar capital costs will fall at a compound annual rate of 1.5%-3% from 2018-2050. Regarding battery energy storage, an even less mature technology, many expect rapid declines due to economies of scale as adoption increases for both storage and electric vehicle applications. In China, 332 GWh of battery manufacturing capacity have been announced by 2021.[7] Despite this general consensus at this time for future declines in cost,

[6] National Renewable Energy Laboratory of the federal Department of Energy
[7] https://www.wsj.com/articles/batteries-are-taking-over-the-world-1511880319

the magnitude and timing of these declines are less certain. Also, as these technologies become more affordable and, consequently, their demand increases, it is uncertain how the offer and their cost will behave in the future.

Solar and solar paired with energy storage, such as lithium-ion (Li-ion) batteries, represent clean and renewable energy options for Puerto Rico that do not require the need for fuel infrastructure or volatility associated with fuel costs. Further, with additional storm hardening tactics like deeper anchoring of ground mounted solar installations, these technologies can withstand significant hurricane conditions. Battery storage technologies can produce or absorb power, providing value to utilities in managing supply to meet load throughout the day. Due to the remote location and hardening requirements, cost premiums (higher costs) for these technologies are assumed in this analysis relative to that, for example, of new solar builds in advantageous areas in the continental U.S. However, the changes in cost outlook even relative to a few years ago are reflected in this IRP analysis as well as a range of outcomes as to the timing and magnitude of these technology cost declines. Overall, however, this trend and the need for a reliable and resilient electric grid present a unique opportunity for Puerto Rico to transition to cleaner, renewable energy sources that by their distributed nature support resiliency.

It is expected that the utilities will deploy huge amounts of solar energy and battery storage, due to the decline in their costs. However, there is no precedent in the electric industry of such deployments and, consequently, there is no experience in developing projects for the simultaneous integration of very large amounts of solar energy and battery storage, in addition to no operational experience managing them. Hence, even though the development of these technologies promises to achieve these benefits, it is important to deploy them in an orderly and planned manner, so the utility is able to acquire the needed operational experience of managing a new technology which has not yet been proved at the large scale that was analyzed in this IRP.

New wind generation is also considered as a part of the IRP analysis. Although the wind technology costs are not declining as noteworthy as solar and battery storage costs, the performance of wind turbines is improving particularly at low wind speeds. This increased performance offers a lower levelized cost of energy from new wind projects. Part 7 – Assumptions and Forecasts provides further details on Siemens forecast.

2.4 Hurricane Impacts on the IRP

Even before the 2017 hurricanes, Puerto Rico's economy was in structural decline, with GNP[8] and population falling by at least a percentage point a year. The devastation of Hurricanes María and Irma in 2017 exacerbated these trends with this event alone resulting in a 4 percent population decline due to migration and the death toll from the storm.[9] These conditions and the uncertainty as to the future population and economy of Puerto Rico are key considerations in this IRP.

Outlooks for economic growth vary between highly credible sources including the Financial Oversight and Management Board (FOMB), the World Bank, and the International Monetary

[8] Gross national product
[9] Per a study from the Harvard T.H. Chan School of Public Health, published in New England Journal of Medicine, May 2018

Fund. Some suggest a relatively fast recovery from the impacts of the hurricanes due to disaster relief spending, structural reforms and improved fiscal transparency in the Government of Puerto Rico (Government). On the other hand, the Puerto Rico Fiscal Plan has the potential to negate some of these economic growth drivers. Central to population and economic growth is a reliable and cost effective electric supply to Puerto Rico.

A more detailed discussion of these impacts, specific to the baseline load projections and range of load uncertainty considered in the IRP analysis, is included in Part 3 – Load Forecast of this report. A real additional risk of future natural disasters in the coming years cannot be ignored. Although these quantum events are difficult to directly include in such an analysis, the range of future market conditions, particularly load growth, aim to incorporate a realistic range of recovery outlooks for Puerto Rico and the resulting impacts to resource decisions over the 20-year planning period are covered in this IRP. It is noted that declining load growth presents a difficult planning environment that requires PREPA to preserve optionality to develop new resilient resources should load growth be higher than forecast.

Puerto Rico's exposure to hurricanes and the disruption that they bring to overhead transmission and distribution facilities necessitates that the IRP identifies an optimal balance between local generation resources and limited centralized new generation. To achieve this, the IRP defines portfolios based on the three strategies detailed in Section 5.2. Central to these strategies is the concept of segregating the system into a number of electrical islands (called MiniGrids), defined considering the vulnerabilities of the overhead transmission system, whose lines could take a month or more to rebuild after a major hurricane, and contain the identification of facilities that need to be hardened (e.g., undergrounding) to ensure integrity of supply to critical loads and timely recovery of the balance of the local loads. Disaster planning is an important component to the IRP and may drive decisions that favor resiliency over other lower cost options. Appendix 1 provides more details.

The IRP analysis will consider a range of load outcomes as Scenarios (High, Base and Low). Additional variables including the cost of fuel and capital costs for new supply options are also analyzed through sensitivities. Scenario and sensitivity analysis will consider alternate regulatory outcomes (i.e. strengthened future renewable mandate) and future fuel supply options (i.e. natural gas availability to fossil generating facilities located at the north of the island).

2.5 PROMESA Federal Act

The Puerto Rico Oversight, Management, ad Economic Stability Act (PROMESA), signed into law by President Obama on June 30, 2016, is a unique federal legislative enactment that includes a number of different provisions that apply to Puerto Rico in respect to its own financial situation. This Law became effective one day before Puerto Rico defaulted on significant payment obligations. Key provisions of PROMESA include:

Financial Oversight and Management Board – PROMESA required a Financial Oversight and Management Board (FOMB) to independently oversee fiscal planning, budgeting, and operations. This Oversight Board consists of seven members appointed by the President of the United States and an ex officio member without voting rights, the Governor or appointee. Among other public entities, PREPA is a listed entity covered by PROMESA and the Oversight Board. As such, activities of PREPA fall under the FOMB, specifically as it relates to its financial planning.

Fiscal Plan – PROMESA requires the development and maintenance of a fiscal plan for Puerto Rico. This plan, at a minimum is required to document the reduction of deficits, payment of debts, and fiscal accountability. Key also to this plan is a description of how critical services, including electric service, will be maintained. Additional contents of PREPA's own fiscal plan are detailed in Part 3 – Load Forecast.

Stay – Title IV of PROMESA implemented a temporary stay on actions and litigation to collect from Puerto Rico entities or enforce liabilities and claims. This stay, similar to protections under the U.S. Bankruptcy code, is enacted to allow Puerto Rico to assess finances and negotiate with creditors.

Debt Reorganization – Title III of PROMESA allows for Puerto Rico or designated representative selected by the FOMB on behalf of the Government to file for reorganizing its debt. This provision maintains elements of Chapter 9 under the U.S. Bankruptcy Code as well as unique provisions specific to Puerto Rico. This includes safe harbors for municipal debts. Title III filing must be approved by the Oversight Board.

2.5.1 Title III

During the Stay period that, with extensions, was in place through May 1, 2017, voluntary negotiations with creditors were ongoing. Following this time, the Oversight Board determined it necessary to file a petition under Title III of PROMESA. The preference is to continue to pursue voluntary negotiations, however the Title III filing was deemed necessary to protect the Government and its people.

As of May 3, 2017, Puerto Rico filed for bankruptcy under Title III of PROMESA. PREPA filed for bankruptcy on July 2017 and became a debtor under Title III of PROMESA. The Government and agencies are working to address the $70 billion debt. PREPA is working with the Government and its statutory fiscal agent, the Fiscal Agency and Financial Advisory Authority (AAFAF), to reach restructuring and the electric sector transformation.

2.5.2 Title V

Title V defines a Critical Project Process which promotes expedited permitting to advance major projects as those that could be identified in the IRP to develop local generation and/or hardened transmission or distribution facilities to provide resiliency.

Title V establishes the position of the "Revitalization Coordinator," who operates under the FOMB and who is charged with evaluating infrastructure projects that will provide direct and substantive benefits to Puerto Rico. After receiving a project proposal, the Revitalization Coordinator identifies all Puerto Rico agencies that have a role in permitting, approving, or authorizing the proposed project, and those agencies are required to submit to the Revitalization Coordinator an expedited permitting process, with the goal of ensuring that critical projects are given priority to the maximum extent possible. In the case of energy projects, the process requires the approval of the PREB. The effectiveness of this procedure is still to be confirmed, but it defines a path that would benefit the implementation of the recommendations of this IRP.

2.6 Fiscal Plan

As noted above, PROMESA required the development of a fiscal plan and budget for Puerto Rico that will supersede previous fiscal plans. PREPA submitted its draft fiscal plan on

February 21, 2017 and the latest plan was published, following updates after the post-hurricane restoration in August 2018. PREPA's fiscal plan aligns with the Government's fiscal plan and addresses areas specific to PREPA. The plan focuses on the need for privatization of assets, efficiency in expenditures, and the need for being an economic growth engine for Puerto Rico.

PREPA's current situation including aging and poorly maintained infrastructure, limited fuel options, and operational challenges drive the current high cost of energy service. The ongoing recession has resulted in lower energy sales, and required subsidized service to certain customers. Growing debt limited PREPA's ability to invest in the grid and the PREPA pension fund. As a result, PREPA's service reliability and infrastructure lags industry standards. The fiscal plan details a path to modernization through transformation. Key to this transformation is the development of PREPA's 2018-2019 IRP. Details and timeline for the IRP are included in the plan.

The fiscal plan presents a path forward covering the term through FY2023[10] based on what is known at this time. Key provisions detailed in the fiscal plan include:

- Behind the meter, distributed generation
- System efficiency, reducing system losses
- Reduce PREPA operating costs (i.e. labor costs and maintenance expenses which were provided by PREPA and reflected in the analysis)
- Updated load outlook to account for post hurricane conditions
- Rates anticipated and rate structure including the ongoing cost of debt service obligation
- Privatization of generating assets

In the fiscal plan, PREPA reports improvements in its liquidity and expectation that it will return to cash flow neutrality in FY2019. Scenarios for post-transformation capital spending and costs are presented. These will be refined and further updated with results of the IRP.

The IRP will be performed within the context of the relevant aspects of the FOMB certified Fiscal Plan for PREPA and the PREPA Governing Board's vision which is presented below.

2.7 PREPA Board Vision Statement

Noting the need for an efficient and resilient system, on February 1, 2018, the PREPA Governing Board released its vision statement to guide the future of the utility. This vision addressed the reliability and resilience of the system, the transition to a sustainable system – both financially and environmentally sustainable – and its importance in acting as an economic growth engine for Puerto Rico. These elements are noted and factored into the structuring of the IRP analysis, Scenarios and sensitivities, and inputs. The vision statement as approved is presented in Exhibit 2-2 below.

[10] FY means Fiscal Year and, hence, FY2023 is the fiscal year starting July 1, 2022 and ending June 30, 2023

Exhibit 2-2. PREPA Vision for the Future of Power in Puerto Rico

Pillar	Summary
System is Customer-Centric	The system serves the customer with affordable, reliable power, with transparent metrics for quality of service and with equitable consideration across all customers. Quality/Reliability can be differentiated for customers in a manner that serves their total cost and risk objectives. Customers are engaged by innovative products and value-added services that provide choice among rate plan and risk management options and provide access to wholesale contracting options for large customers. Customers are empowered with behind-the-meter alternatives for energy efficiency, demand management, and distributed generation, with the ability to become prosumers if they so choose.
System Promotes Financial Viability	The system is premised on positive economics on both sides of the meter. Rates are reasonable and create value for the customer, while pricing is sufficient to cover costs. Rate and market design create incentives to purchase, consume or produce energy in a manner that benefits the entire system. Subsidies are minimized, and those that remain have a non-distortionary impact. Operational excellence and sound long term planning reduce the cost to serve. Rates are affordable within a model that allows the utility to earn a reasonable rate of return and service its debt. The business model is robust to changes such as outmigration and reduction in energy demand and does not create disincentives for adoption of cheaper energy resources, either at the grid level or at the customer premises.
System is Reliable and Resilient	The grid is thoughtfully planned, well maintained and safely operated to achieve defined reliability and resiliency goals. There is visibility into the system at all levels, and control where appropriate. Standards for recoverability create a measure for resilience. The choice of architecture (distributed vs. regionalized vs. centralized) is intentionally made to balance reliability/resilience and cost objectives while also taking advantage of advancements in technology and innovation.
System is a Model of Sustainability	There is a progressive focus on diversifying energy resources and reducing the carbon intensity of the power sector, in both primary generation and backup generation. Power generation is efficient and minimizes emissions. Customers have incentives to use energy wisely and to generate their own clean energy. The grid and grid systems are designed to take maximum advantage of increasingly cost effective renewable power generation alternatives and to integrate emerging technologies.
System serves as an Economic Growth Engine for Puerto Rico	The quality, reliability, and cost of power attracts new commercial and industrial development to Puerto Rico and encourages existing commercial and industrial customers to expand their operations. Transformation and reinvestment in the power system creates new jobs. Innovation in the generation and delivery of power creates a local ecosystem of businesses that provide for evolving needs for equipment, technology and services in Puerto Rico and beyond.

Source: PREPA, 2018

2.8 Privatization

The Governor of Puerto Rico has publicly stated that the reconstruction and transformation of the electricity sector will include the privatization of PREPA's generating facilities. This would include the generating assets and be complemented by the operation of the transmission and distribution system by a third party. The Law to Transform the Electric System of Puerto Rico was passed on June 12, 2018, becoming Act 120-2018 (and since amended). As a means to transform Puerto Rico's electric system into a modern and sustainable one, system ownership including generating assets will be open to private entities. PREPA and Puerto Rico's Authority for Public-Private Partnerships are to collaborate in the process to privatize assets. Final agreements would need to be ratified by Puerto Rico's Legislature and the Governor.

Request for Proposals are to be issued for PREPA's owned generating units. Bids will be evaluated on metrics that balance commercial interests and social responsibility as well as the bidder's interest and ability to transition to cleaner generating sources when reasonably possible. The act also requires the PREB to sign off on the sales and regulate tariffs and other charges for electricity following the transactions. Under the act, the PREB has fifteen days to review and decide on the approval. Approved contracts would be issued an "energy compliance certificate". Finally, the act expands the PREB's staff to facilitate timely decisions.

Based on the Act 120-2018 authorizing PREPA to sell its generating assets to more than one private buyers, Siemens considered future builds to be financed by third parties, assuming PREPA obtains financial backing to contract as a credit-worthy counterparty if needed. Should Federal funding become available, it has the potential to significantly alter financing assumptions and impact the implementation of the IRP's action plan.

Part
3

Load Forecast

This Part covers Siemens load forecast methodology and results. The energy efficiency and demand response complementary to this analysis are presented in Appendix 4.

3.1 Data, Assumptions and Methodology

3.1.1 Historical Energy Sales

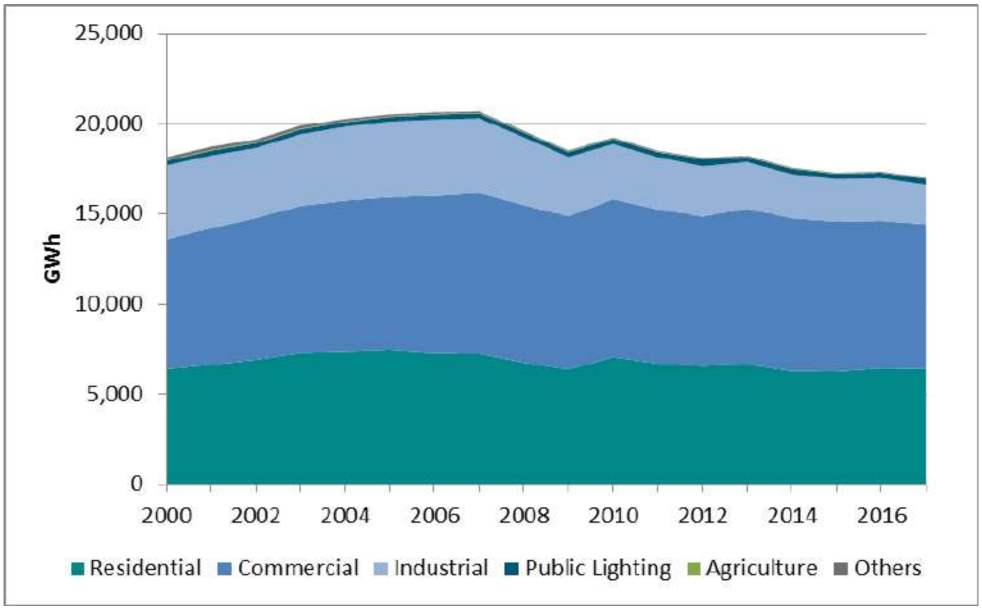
PREPA provided monthly historical energy sales for July 1999 – June 2018 (Fiscal Years 2000 – 2008) divided into six customer classes: residential, commercial, industrial, agriculture, public lighting, and other. The commercial sector accounted for 47% of the total sales in FY 2017, followed by residential at 38% and industrial at 13%. Overall, sales to residential, commercial, and industrial customers represented 98% of total sales in FY 2017, the remaining 2% originated from the public lightning sector. These FY 2017 results are generally consistent with the results of recent historical years for sales by customer class.

Electricity sales in Puerto Rico declined by 18% since the 2008 recession and net migration. Starting in 2007 until 2017, Puerto Rico's real gross national product (GNP) shrank by approximately 17% and the population declined by over 15%[11]. For FY 2018, total energy sales declined 22%, reflecting the disruption in the transmission and distribution networks due to the hurricanes as well as customer billing delays[12].

Industrial sales declined by 47% in FY 2007 to FY2017, while residential and commercial sales fell 12% and 10% respectively. Industrial share of the total energy sales declined from 20% in FY 2007 to 13% in FY 2017. In contrast, the share of commercial sales increased by 4 percentage points. Exhibit 3-1 and 3-2 show historical energy sales for FY 2000 to FY2017 by customer class. Exhibit 3-3 shows the historical system level demand and generation.

[11] Based on data provided by the Financial Oversight & Management Board (FOMB)
[12] Based on preliminary data provided by PREPA

Exhibit 3-1. Historical PREPA Annual Sales by Customer Class (GWh)



Source: PREPA

Exhibit 3-2. Historical PREPA Annual Sales by Customer Class (GWh)

Calendar Year	Residential	Commercial	Industrial	Public Lighting	Agriculture	Others	Total
2000	6,482	7,498	4,101	281	41	165	18,569
2001	6,742	7,632	3,934	253	42	163	18,766
2002	7,120	8,017	3,931	265	43	189	19,565
2003	7,359	8,343	4,005	259	40	159	20,163
2004	7,298	8,371	4,104	256	33	115	20,177
2005	7,460	8,693	4,258	263	34	99	20,806
2006	7,215	8,808	4,213	266	33	85	20,618
2007	7,058	8,866	3,938	270	32	66	20,230
2008	6,473	8,660	3,544	273	30	60	19,040
2009	6,673	8,568	3,094	281	31	57	18,704
2010	6,975	8,677	2,968	280	29	55	18,984
2011	6,587	8,473	2,832	282	28	50	18,251
2012	6,771	8,390	2,683	387	28	61	18,319
2013	6,320	8,621	2,504	285	27	35	17,793
2014	6,218	8,395	2,376	298	26	35	17,348
2015	6,306	8,199	2,355	312	26	37	17,235
2016	6,504	8,176	2,250	319	26	35	17,311
2017	5,012	6,505	1,741	247	20	33	13,558
2018	6,051	7,758	2,128	378	21	38	16,375

Source Workpaper: Historical Customer Energy by Class.xlsx

Exhibit 3-3. Historical System Level Demand and Generation (GWh)

Demand and Generation			
Calendar Year	Peak Demand (MW)	Gross Generation (GWh)	Net Generation (GWh)
2007	3,546	24,636	23,720
2008	3,351	23,214	22,337
2009	3,404	22,989	22,022
2010	3,406	23,244	22,216
2011	3,303	22,257	21,284
2012	3,265	22,306	21,297
2013	3,159	21,493	20,621
2014	3,030	21,067	20,272
2015	3,080	20,911	20,082
2016	3,087	20,644	19,880
2017*	3,060	16,361	15,698
2018	2,705	17,453	16,789

*In September 2017, Puerto Rico Electrical System was affected by Hurricanes Irma and Maria.

Source Workpaper: Historical Generation and System Load.xlsx

PREPA and Financial Oversight & Management Board (FOMB) provided historical data such as population, gross national product (GNP), and weather. These data along with long-term projections of GNP and population were leveraged to create a model and develop gross load forecasts by customer class.

3.1.2 Load Forecast Methodology

The load forecasting methodology employed customer-class specific, statistical and econometric time-series models to develop forecasted monthly energy sales for the three largest customer classes: residential, commercial and industrial. The gross energy consumption forecast was developed using a Classical Linear Regression Model (CLRM) in which the dependent variable, energy sales, is expressed as a linear equation combining the independent variables. For Puerto Rico, 15 variables were used including:

- a weather variable (cooling degree days or CDD)
- two economic variables (population and GNP)
- 12 month specific dummy variables (one for each month of the year) to capture the seasonality of energy demand on a monthly basis

Population was found not to have a statistical significance for industrial. Therefore, manufacturing employment was substituted for population as an independent variable in the regression analysis used to forecast industrial energy consumption.

The econometric model uses an ordinary least-squares regression technique and is developed in MATLAB[13]. This basic approach is widely used to develop long-term load forecasts for independent system operators like PJM, the California Energy Commission and individual utilities. Siemens used monthly historical data for FY 2000 through FY 2017 to estimate the regression coefficients applied to the forecast, with 210 observations for each variable.

The unique coefficients that are produced for each independent variable are used to develop the gross energy sale forecast. The 12 monthly dummy binary variables were included in the forecast formulation to capture monthly seasonality in demand. The sum product of the coefficients and variables on a monthly basis result in the gross energy forecast equation is shown below:

$$Demand = C_1 * V_1 + C_2 * V_2 \dots \dots \dots C_{17} * V_{17} + b$$

In the equation above, C_x is the coefficient corresponding to each independent variable V_x, and *b* represents a constant.

The statistical significance and predicted fit of the model for residential, commercial, and industrial classes was robust, with all three customer classes combined representing approximately 98% of the total load, in line with historical values. Exhibit 3-4 illustrates the variables used to develop the forecast for each of three largest classes.

Exhibit 3-4. Independent variables for Each Customer Classes

Residential	Commercial	Industrial
▪ CDD ▪ GNP ▪ Population ▪ 12 months variable	▪ CDD ▪ GNP ▪ 12 months variable	▪ CDD ▪ GNP ▪ Manufacturing employment ▪ 12 months variable

For the smaller customer classes (agriculture, lighting, and other) the overall fit of the CLRM model was weak with the economic and weather fundamental variables providing little explanatory value on the energy consumption for each class. For these customer classes, Siemens developed the forecast of energy consumption for these three classes based on historical seasonality and using a simple extrapolation technique with the expectation that each class will follow similar growth rate as the overall system. This simpler forecast method was deemed acceptable since the three classes collectively represented approximately 2% of the total energy consumption.

[13] MATLAB is a numerical computing environment and proprietary programming language developed by MathWorks

3.1.3 Fundamental Drivers for the Load Forecast

In line with the econometric model, Siemens used population, GNP, CDD and the monthly dummy variables as explanatory variables to develop the load forecast by customer class for FY 2019–2038. Other economic data considered included disposable income, income per-capita, and the heat index for weather. However, these additional independent variables were ultimately not incorporated in the final forecast due to their high correlation to other variables already incorporated in the analysis such as CDD (highly correlated to the heat index) or the GNP (highly correlated to disposable income), which diluted their predictive value.

For weather data, Siemens found CDD as the most significant statistically variable to predict the impact of weather on load, which is consistent with Puerto Rico having a tropical climatic zone with year-round warm temperatures averaging 80°F (27°C) in low elevation areas, and 70°F (21°C) in the central mountains of the island. Although temperature variation is relatively modest throughout the year, the overall heat level drives cooling load trends (demand for air conditioning). Weather data was sourced from the National Oceanic and Atmospheric Association (NOAA) for the San Juan station, as a representative for the overall island temperature and rainfall trends. Higher elevation locations were not found to have a significant impact on overall load changes.

Customer rates were considered in the analysis, in particular industrial rates, but they were found not to have a strong historic correlation to demand and explanatory power. From 2000 to 2017, there were periods where industrial demand fell along with declining industrial rates or the opposite. The expectation would be an inverse relationship with lower demand as a consequence of rising industrial rates. The manufacturing sector in Puerto Rico, mostly comprised of pharmaceutical, textiles, petrochemicals, and electronics; appears to be less responsive to changes in customer rates compared to other manufacturing industries such as steel or aluminum, which are highly sensitive (high elasticity). The residential sector is traditionally a sector with low response to changes in retail rates and to some extend the commercial customers. However, sustained high retail rates could change customer behavior and create more incentives for implementation of energy efficiency programs.

Siemens compiled and reviewed macroeconomic data (historical and forecasts) from several sources including Moody's Analytics, the International Monetary Fund, World Bank, the U.S. Census Bureau, Federal Reserve of Economic Data of St. Louis (FRED) and Puerto Rico's Federal Management Oversight Board (FOMB), among others.

Exhibit 3-3 below shows the historical annual values for the independent variables used in the regression analysis.

Exhibit 3-5. Historical Population, Macroeconomic, and Weather Variables

Year	Population (thousands)	GNP (Real Million US dollars)	Cooling Degree Days (Monthly Average)	Manufacturing Employment (thousands)
2000	3,815	6,773	453	143
2001	3,822	6,873	476	132
2002	3,825	6,850	477	121
2003	3,827	6,991	472	118
2004	3,825	7,178	461	118
2005	3,814	7,315	478	115
2006	3,794	7,351	473	110
2007	3,772	7,262	489	106
2008	3,750	7,054	467	101
2009	3,733	6,784	499	92
2010	3,702	6,542	491	87
2011	3,656	6,432	462	84
2012	3,615	6,466	506	82
2013	3,566	6,458	496	76
2014	3,504	6,348	519	75
2015	3,441	6,312	513	74
2016	3,372	6,209	506	74
2017	3,190	6,060	504	72

Source: FOMB (GNP), Moody's Analytics (Population), NOAA (weather), Federal Reserve Bank of St. Louis Economic Data - FRED (Manufacturing Employment)

Before the hurricane, Puerto Rico's economy was in structural decline, with GNP and population falling by at least a percentage point a year since 2006, the last year when the GNP saw an increase. Puerto Rico's GNP shrunk 8% in the decade after the Great Recession with GNP reaching $6 billion dollars in 2017 (real dollars).

Population declined 15% since 2007 with Maria and Irma accounting for 4 percentage points of this decline in population (182 thousand people in 2017) due to the combined impact of migration and the death toll after the storm, estimated at over 4,100 people[14].

3.1.4 Macroeconomic and Weather Projections

Historical monthly NOAA data was utilized (2000-2016) to develop expected monthly CDD under normal weather conditions. The expected normal weather conditions and its associated monthly CDD was used as a common basis for each year of the energy sales forecast. Exhibit 3-4 shows the normalized CDD used for the forecast.

[14] Per a study from the Harvard T.H. Chan School of Public Health, published in New England Journal of Medicine, May 2018

Exhibit 3-6. Weather Variables

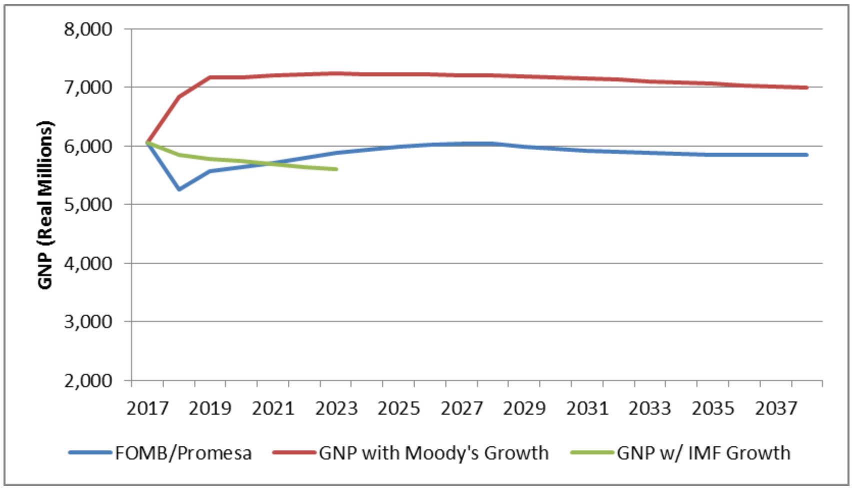
Month	Cooling Degree Days (CDD)
January	391
February	361
March	427
April	454
May	511
June	547
July	567
August	572
September	552
October	552
November	466
December	427

Source: NOAA, Siemens

To be consistent with the FOMB, Siemens used their historical and forecasted data for GNP and population in 2019–2038. According to FOMB, the GNP is estimated to decline 13% for FY 2018, reflecting the impact of hurricanes Maria and Irma on the economy. However, GNP is projected to grow at 6.1% in FY 2019. FOMB forecast shows a relatively fast recovery from Maria's impact, driven by the effect of the Disaster Relief Fund spending program. In the medium-term GNP is projected to increase at 1.6% per-year in 2019-2027. After 2027, GNP growth is projected to soften to -0.3% per-year. The structural reforms are projected to enhanced economic growth, including a reform of the electrical grid, enhanced fiscal transparency and a labor reform aimed to bring Puerto Rican labor law into closer alignment with U.S. law. An offset to economic growth is expected to come from the proposed fiscal consolidation plan which could bring significant austerity over the next few years to reduce Puerto Rico's public debt.

Siemens considered other outlooks as well, including Moody's Analytics (Moody's) and the International Monetary Fund (IMF), as shown on Exhibit 3-5. Moody's projects the GNP to recoup much of its hurricane-related losses and to remain relatively stable throughout the forecast horizon. The IMF shows a more pessimistic forecast through 2023 with GNP not recovering from the aftermath of hurricane Maria through 2023.

Exhibit 3-7. Puerto Rico GNP Forecasts

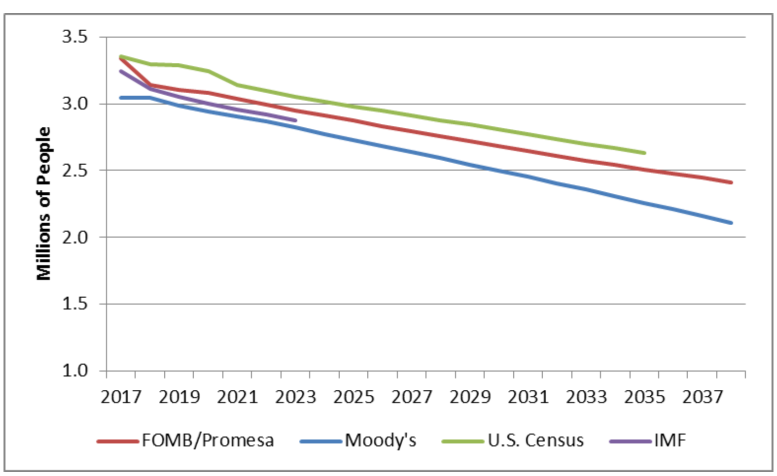


Note: The forecast have been standardized for comparison purposes using the implied growth rates. Moody's GNP forecast is based on real 2009$ and the IMF based on real 1954$.

Sources: Moody's June 2018 Forecast, IMF April 2018 WEO, Financial Oversight and Managing Board of Puerto Rico, Fiscal Plan April 2018

The FOMB forecast for population shows a decline of 5.8% in FY2018 due to hurricane fatalities and net migration off the island. Over the study period, FOMB projects population to decline at 1.3% per year in 2019–2038. Population in Puerto Rico is projected to fall by over 900 thousand people by 2038. Moody's projects a faster pace of population loss over the next decade, compared to FOMB, as the island gets increasingly dragged into a negative feedback loop whereby out-migration undermines the tax base and the provision of public services (which deteriorated since Hurricane Maria), will engender more out-migration. The U.S. Census (prior to Maria) projects higher population levels but still with a falling trend through the forecast. The IMF provides a forecast between the projections from FOMB and Moody's.

Exhibit 3-8. Puerto Rico Population Forecast



Sources: Moody's June 2018 Forecast, IMF April 2018 WEO, US Census Bureau August 2017

Exhibit 3-7 shows the long-term economic forecast used in the load forecast.

Exhibit 3-9. Macroeconomic Long Term Forecast

Fiscal Year	Population (thousands of people)	GNP (Real Millions US dollars)	Manufacturing Employment (thousands of people)
2018	3,143	5,251	70
2019	3,104	5,573	69
2020	3,084	5,632	70
2021	3,039	5,707	70
2022	2,995	5,792	70
2023	2,951	5,873	70
2024	2,910	5,941	71
2025	2,871	5,991	71
2026	2,833	6,029	71
2027	2,794	6,041	72
2028	2,756	6,038	72
2029	2,718	5,984	73
2030	2,681	5,949	73
2031	2,644	5,922	74
2032	2,609	5,897	74
2033	2,575	5,877	75
2034	2,541	5,862	75
2035	2,508	5,852	76
2036	2,476	5,847	77
2037	2,445	5,846	77
2038	2,414	5,849	78

Source: FOMB (population and GNP), Siemens for Manufacturing employment

3.1.5 Gross Long Term Energy Forecast

Exhibit 3-8 shows Siemens forecasted gross energy sales by customer class. The forecast does not include any future energy efficiency (EE) and/or demand response programs and distributed generation (DG). The impact of those programs is addressed in the sections below. The forecast does include the impact of naturally occurring energy efficiency savings, such as more efficient household appliances, in as much these efficiency savings are embedded in the historical energy consumption data used to create the forecast. It also includes the existing levels of Distributed Generation, which was later extracted to create the inputs to the Aurora Model that has the distributed generation modeled as a resource.

Exhibit 3-10. Gross Sales Demand by Customer Class

Fiscal Year	Residential Sales (GWh)	Commercial Sales (GWh)	Industrial Sales (GWh)	Agricultural Sales (GWh)	Public Lighting Sales (GWh)	Other Sales (GWh)	Total Sales (GWh)
2019	5,472	7,962	1,491	26	315	35.6	15,301
2020	5,480	7,948	1,551	26	316	35.8	15,357
2021	5,473	7,917	1,635	26	317	35.9	15,403
2022	5,473	7,886	1,730	26	318	36.0	15,470
2023	5,470	7,856	1,822	27	320	36.2	15,530
2024	5,464	7,827	1,900	27	320	36.3	15,574
2025	5,451	7,801	1,960	27	321	36.3	15,595
2026	5,431	7,774	2,008	27	321	36.3	15,596
2027	5,396	7,747	2,028	27	320	36.2	15,554
2028	5,353	7,721	2,032	26	319	36.1	15,487
2029	5,284	7,695	1,984	26	316	35.7	15,341
2030	5,223	7,669	1,956	26	313	35.5	15,223
2031	5,168	7,644	1,937	26	311	35.2	15,120
2032	5,115	7,619	1,921	26	309	35.0	15,025
2033	5,065	7,596	1,910	26	307	34.8	14,939
2034	5,020	7,572	1,905	25	306	34.6	14,862
2035	4,978	7,549	1,905	25	304	34.5	14,796
2036	4,940	7,527	1,911	25	303	34.3	14,741
2037	4,905	7,506	1,921	25	302	34.2	14,694
2038	4,873	7,484	1,935	25	302	34.1	14,654
CAGR	**-0.61%**	**-0.32%**	**1.38%**	**-0.23%**	**-0.23%**	**-0.23%**	**-0.23%**

Note: The sales forecasts reflect gross energy sales inclusive of existing EE programs. It does not include loses, PREPA's own use and auxiliary demand neither any future incremental EE and/or demand response programs.
Source Workpaper: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm

Gross energy sales are projected to increase by 15% in fiscal year 2019 due to the projected, near-term recovery in the economy. However, over the full 20-year study period, gross energy sales are projected to decline at average of 0.23% per-year driven by the long-term decline in population and softening of the GNP growth after 2027. Among customer classes, the industrial class is the only customer class projected to have a positive average growth over the study period, at an average of 1.4% per-year, primarily driven by the projected economic growth through 2026. In contrast, the residential and commercial classes are projected to decline by an average of 0.6% and 0.3% per-year, mostly driven by the long-term decline in population.

Agriculture, public lightning and "other" are projected to decline in line with the overall system average of -0.23% per year. The public lighting forecast does not include the impact of a wide spread replacement of the current metal-vapor-based public lightning with LED light bulbs. LED replacement and other energy efficiency programs are addressed in a separate document; however, at the end of this report, Siemens provides a summary of the effects of energy efficiency programs on the load forecast.

Exhibit 3-9 illustrates the gross energy demand inclusive of the generation auxiliary loads, technical and non-technical loses, and PREPA's own use. The first column, gross energy sales, reflects the totals from the exhibit above. PREPA's own use is assumed to stay

constant through the forecast. The forecast includes no material change in the auxiliary generation load, and for modeling purposes is assumed to be constant until the plants retire. However, as plants retire there is an impact on demand.

Exhibit 3-11. Gross Energy Demand for Generation

Fiscal Year	Gross Energy Sales (GWh)	Technical Losses (GWh)	Non-Technical Losses (GWh)	Auxiliary (GWh)	PREPA Own Use (GWh)	Total Energy Demand (GWh)
2019	15,301	1,438	827	751	34	18,351
2020	15,357	1,444	830	751	34	18,415
2021	15,403	1,448	832	751	34	18,469
2022	15,470	1,454	836	751	34	18,545
2023	15,530	1,460	839	751	34	18,613
2024	15,574	1,464	841	751	34	18,665
2025	15,595	1,466	842	751	34	18,689
2026	15,596	1,466	843	751	34	18,690
2027	15,554	1,462	840	751	34	18,642
2028	15,487	1,456	837	751	34	18,565
2029	15,341	1,442	829	751	34	18,397
2030	15,223	1,431	822	751	34	18,261
2031	15,120	1,421	817	751	34	18,144
2032	15,025	1,412	812	751	34	18,034
2033	14,939	1,404	807	751	34	17,935
2034	14,862	1,397	803	751	34	17,848
2035	14,796	1,391	799	751	34	17,772
2036	14,741	1,386	796	751	34	17,708
2037	14,694	1,381	794	751	34	17,654
2038	14,654	1,377	792	751	34	17,608
CAGR	**-0.23%**	**-0.23%**	**-0.23%**	**0.00%**	**0.00%**	**-0.22%**

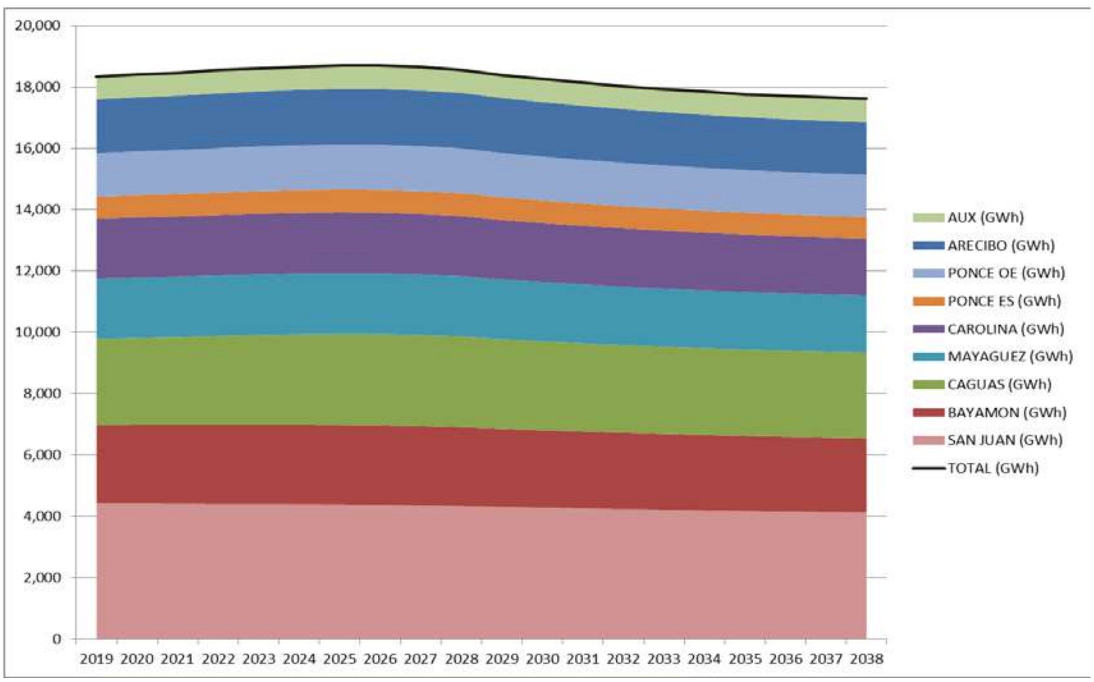
Source Workpaper: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm

To assess the geographical location of the demand above, as necessary for the modeling of the system, PREPA provided the composition of the load in term of customer classes (residential, commercial, industrial, etc.) by County which was used to map the forecast to each of the areas into which the system is modeled. Exhibit 3-10 and Exhibit 3-11 shows the resulting allocation of the Energy Demand for Generation above in tabular and graphic form.

Exhibit 3-12. Gross Energy Demand for Generation by Area

Fiscal Year	ARECIBO (GWh)	BAYAMON (GWh)	CAGUAS (GWh)	CAROLINA (GWh)	MAYAGÜEZ (GWh)	PONCE ES (GWh)	PONCE OE (GWh)	SAN JUAN (GWh)	AUX (GWh)	TOTAL (GWh)
2,019	1,748	2,558	2,818	1,956	1,961	719	1,422	4,417	751	18,351
2,020	1,759	2,566	2,840	1,961	1,966	724	1,429	4,418	751	18,415
2,021	1,771	2,571	2,866	1,965	1,969	729	1,436	4,411	751	18,469
2,022	1,787	2,579	2,898	1,970	1,974	736	1,445	4,406	751	18,545
2,023	1,801	2,585	2,927	1,975	1,978	742	1,453	4,401	751	18,613
2,024	1,813	2,590	2,951	1,978	1,981	746	1,460	4,394	751	18,665
2,025	1,820	2,591	2,968	1,979	1,981	750	1,464	4,385	751	18,689
2,026	1,824	2,589	2,978	1,978	1,979	751	1,466	4,374	751	18,690
2,027	1,821	2,581	2,975	1,971	1,972	750	1,462	4,357	751	18,642
2,028	1,815	2,569	2,965	1,962	1,963	747	1,457	4,337	751	18,565
2,029	1,794	2,544	2,930	1,945	1,945	739	1,442	4,307	751	18,397
2,030	1,779	2,524	2,903	1,930	1,931	732	1,430	4,280	751	18,261
2,031	1,766	2,506	2,882	1,917	1,918	727	1,420	4,256	751	18,144
2,032	1,755	2,490	2,862	1,905	1,905	722	1,411	4,233	751	18,034
2,033	1,744	2,475	2,845	1,894	1,894	717	1,403	4,211	751	17,935
2,034	1,736	2,461	2,831	1,885	1,884	714	1,396	4,191	751	17,848
2,035	1,728	2,449	2,820	1,876	1,875	710	1,390	4,172	751	17,772
2,036	1,723	2,439	2,812	1,868	1,867	708	1,385	4,155	751	17,708
2,037	1,719	2,430	2,806	1,862	1,860	706	1,381	4,139	751	17,654
2,038	1,715	2,422	2,802	1,856	1,854	705	1,378	4,124	751	17,608

Exhibit 3-13. Graph of Gross Energy Demand for Generation by Area



Source: Siemens

3.1.6 Net Long Term Energy Forecast

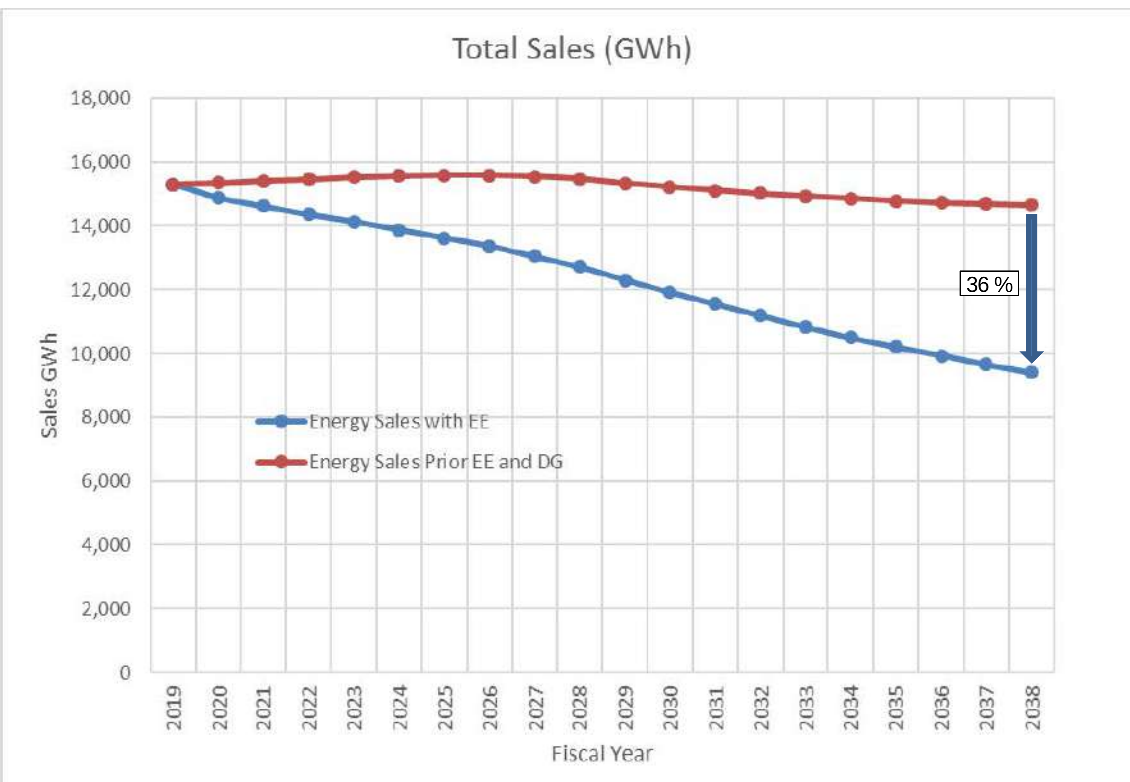
The Gross Energy forecast above is affected by two key factors discussed in further detail in Appendix 4; the Energy Efficiency that is assumed to achieve gains of approximately 2% per year until from 2020 until 2037 and the customer owned distributed generation.

The exhibit below shows the energy sales by customer class including the effects of EE and a graphical comparison with the forecast before EE.

Exhibit 3-14. Sales Demand by Customer Class after EE

Fiscal Year	Residential Sales (GWh)	Commercial Sales (GWh)	Industrial Sales (GWh)	Agricultural Sales (GWh)	Public Lighting Sales (GWh)	Other Sales (GWh)	Total Sales (GWh)
2019	5,472	7,962	1,491	26	315	36	15,301
2020	5,226	7,760	1,551	26	275	36	14,874
2021	5,145	7,541	1,635	26	234	36	14,617
2022	5,070	7,322	1,730	26	194	36	14,379
2023	4,992	7,103	1,822	27	153	36	14,133
2024	4,910	6,887	1,900	27	112	36	13,872
2025	4,821	6,672	1,960	27	112	36	13,628
2026	4,724	6,458	2,008	27	113	36	13,364
2027	4,612	6,243	2,028	27	112	36	13,057
2028	4,491	6,028	2,032	26	110	36	12,725
2029	4,343	5,814	1,984	26	107	36	12,311
2030	4,203	5,601	1,956	26	105	35	11,926
2031	4,068	5,387	1,937	26	103	35	11,556
2032	3,935	5,175	1,921	26	101	35	11,193
2033	3,805	4,963	1,910	26	99	35	10,838
2034	3,678	4,752	1,905	25	98	35	10,492
2035	3,605	4,541	1,905	25	96	34	10,207
2036	3,536	4,331	1,911	25	95	34	9,932
2037	3,469	4,121	1,921	25	94	34	9,665
2038	3,406	3,912	1,935	25	93	34	9,405
CAGR	**-2.47%**	**-3.67%**	**1.38%**	**-0.23%**	**-6.21%**	**-0.23%**	**-2.53%**

Exhibit 3-15. Comparison Sales Demand by Customer Class before and after EE



Source Workpaper: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm

As can be observed by the end of the period the drop in energy sales due to EE represents 36% of the original demand.

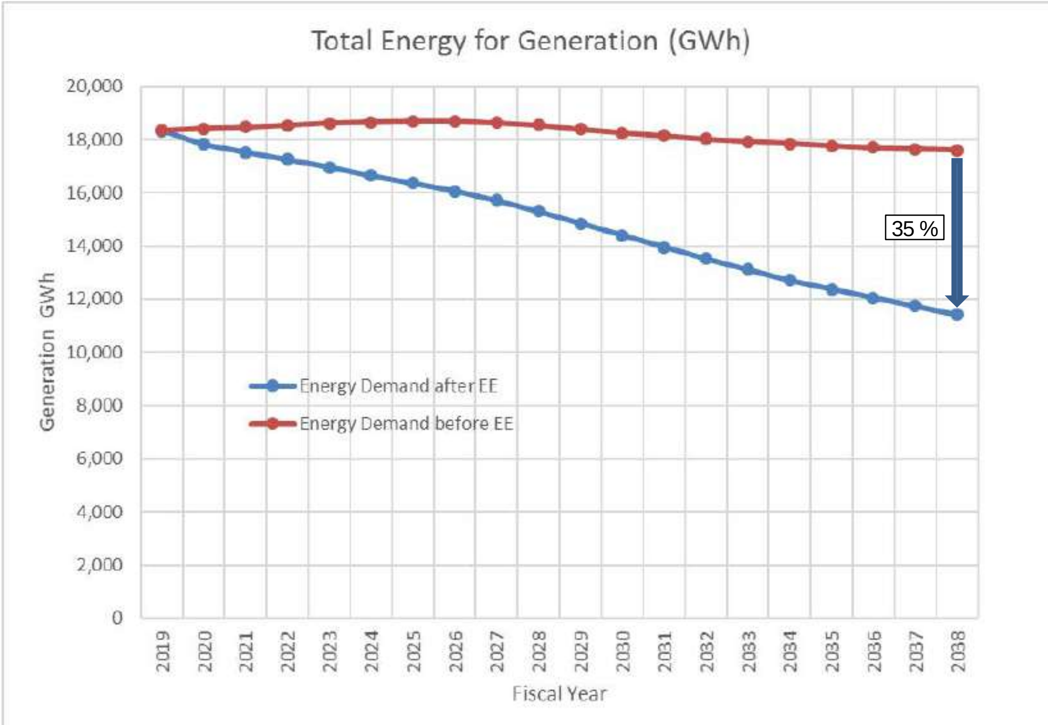
Considering the effect of PREPA's own use, auxiliary generation load and the losses the net demand for generation is expected to decline by 35% after EE is accounted for, as shown in the exhibits below. In these exhibits the technical losses are also adjusted to account for the impact of DG that is particularly important for the distribution losses, as the distribution feeders are not modeled and the loads plus the DG are represented at the medium voltage side of the transmission (HV) to distribution (MV) substations. Transmission level losses are properly accounted for on load flows assessment, but as the LTCE is carried out without the modeling of losses, again it is important to make this adjustment.

Exhibit 3-16. Energy Demand for Generation after EE

Fiscal Year	Gross Energy Sales (GWh)	Technical Losses (GWh)	Non-Technical Losses (GWh)	Auxiliary (GWh)	PREPA Own Use (GWh)	Total Energy Demand (GWh)
2019	15,301	1,412	827	751	34	18,324
2020	14,874	1,367	803	751	34	17,829
2021	14,617	1,338	790	751	34	17,529
2022	14,379	1,310	777	751	34	17,251
2023	14,133	1,283	763	751	34	16,964
2024	13,872	1,253	749	751	34	16,659
2025	13,628	1,225	736	751	34	16,375
2026	13,364	1,195	722	751	34	16,066
2027	13,057	1,160	705	751	34	15,708
2028	12,725	1,123	687	751	34	15,320
2029	12,311	1,078	665	751	34	14,839
2030	11,926	1,035	644	751	34	14,390
2031	11,556	993	624	751	34	13,958
2032	11,193	951	605	751	34	13,533
2033	10,838	910	585	751	34	13,118
2034	10,492	869	567	751	34	12,713
2035	10,207	834	551	751	34	12,377
2036	9,932	799	537	751	34	12,052
2037	9,665	765	522	751	34	11,737
2038	9,405	731	508	751	34	11,429
CAGR	**-2.53%**	**-3.41%**	**-2.53%**	**0.00%**	**0.00%**	**-2.45%**

Source Workpaper: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm

Exhibit 3-17. Comparison Energy Demand for Generation before and after EE



Source Workpaper: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm

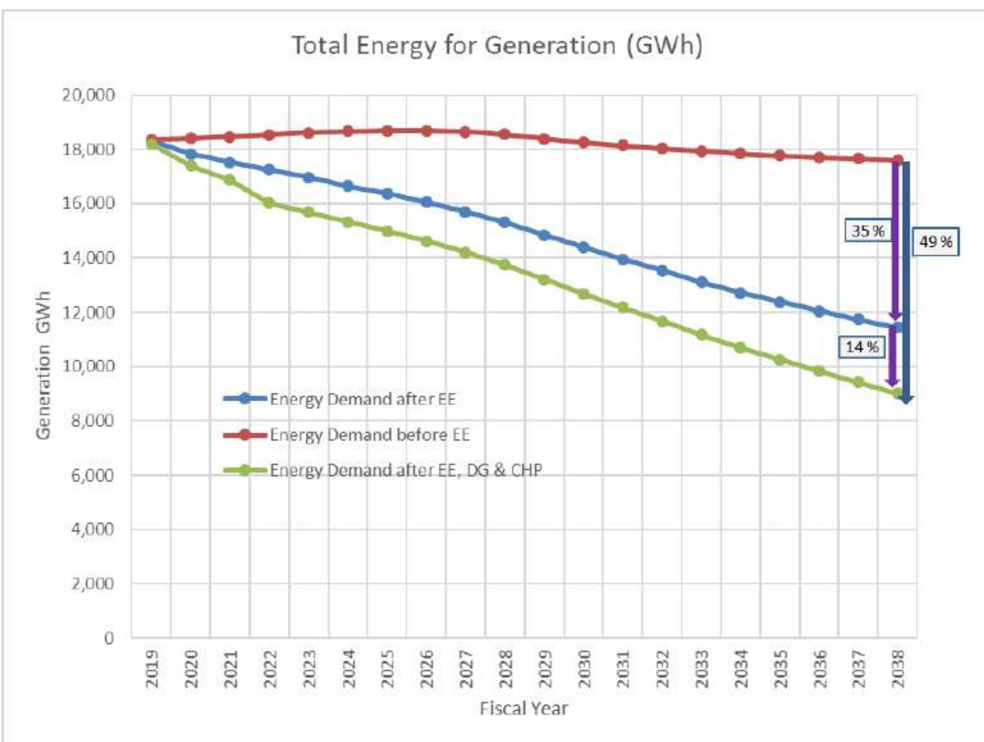
The exhibit below shows the impact of customer owned generation (DG and CHP) on the Total Energy Demand after EE shown previously. Note that the (DG and CHP values reported are the increases in this generation as the existing (2018 values) is already included in the projections.

As can be observed after Energy Efficiency and customer owned generation there is a reduction of 49% with respect of the demand before these effects. Another aspect that is important to note is that the utility served energy demand is projected to drop by 40% from 2025 to 2038 (14,996 GWh to 9,012 GWh). This steep drop combined with the requirement to meet 40% of the energy from renewable resources (Act 82-2010 as amended by Act 17-2019) by 2025, makes the process of finding an optimal solution very challenging as the resources needed short term see a drastic reduction in the utilization over the long term. However, the resources needed for the short term could become key reliability resources should Energy Efficiency and customer owned generation not materialize at the levels forecasted. This risk requires that PREPA plan for and preserve optionality to serve potential higher load scenarios.

Exhibit 3-18. Impact of Customer Owned Generation on the Energy Demand for Generation after EE

Fiscal Year	Total Energy Demand (GWh)	New Customer Owned Distributed Generation (GWh)	New CHP (GWh)	Total Energy Demand after DG & CHP (GWh)
2019	18,324	62	66	18,196
2020	17,829	183	236	17,410
2021	17,529	249	404	16,876
2022	17,251	300	922	16,028
2023	16,964	350	922	15,692
2024	16,659	404	922	15,333
2025	16,375	456	922	14,996
2026	16,066	514	922	14,630
2027	15,708	575	922	14,211
2028	15,320	642	922	13,755
2029	14,839	708	922	13,209
2030	14,390	781	922	12,687
2031	13,958	857	922	12,179
2032	13,533	941	922	11,670
2033	13,118	1,022	922	11,174
2034	12,713	1,109	922	10,682
2035	12,377	1,200	922	10,255
2036	12,052	1,298	922	9,831
2037	11,737	1,392	922	9,422
2038	11,429	1,494	922	9,012
CAGR	**-2.45%**	**18.25%**	**14.86%**	**-3.63%**

Exhibit 3-19. Comparison Energy Demand for Generation before and after EE & Customer Owned Generation



Source Workpaper: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm

3.1.7 Assessments of prior forecasts

The IRP Regulation issued by the PREB requires the load forecast evaluation include:

- Comparisons of prior forecasts versus actual data
- An explanation of the cause of any significant deviation between the prior forecasts and the actual annual peak demand and energy that occurred
- An explanation of the impact that historical demand—side resources had on the prior load forecast.

Siemens believes the comparisons with actual data to recent forecasts have been rendered meaningless by structural changes in the island population, economy and energy consumption that have taken place as a result of Hurricane Maria. A more meaningful comparison is the significant changes resulting from Hurricane Maria to the forecasts. Exhibit 3-14Illustrates the differences in the customer class level energy sales forecasts developed for the 2015 IRP and the forecasts developed for this 2018 IRP. Exhibit 3-15 provides a comparison of the forecasted total energy sales from the 2015 IRP versus this 2018 IRP.

Exhibit 3-20: Comparison of 2015 versus 2018 IRP Forecasted Class-Level Energy Sales

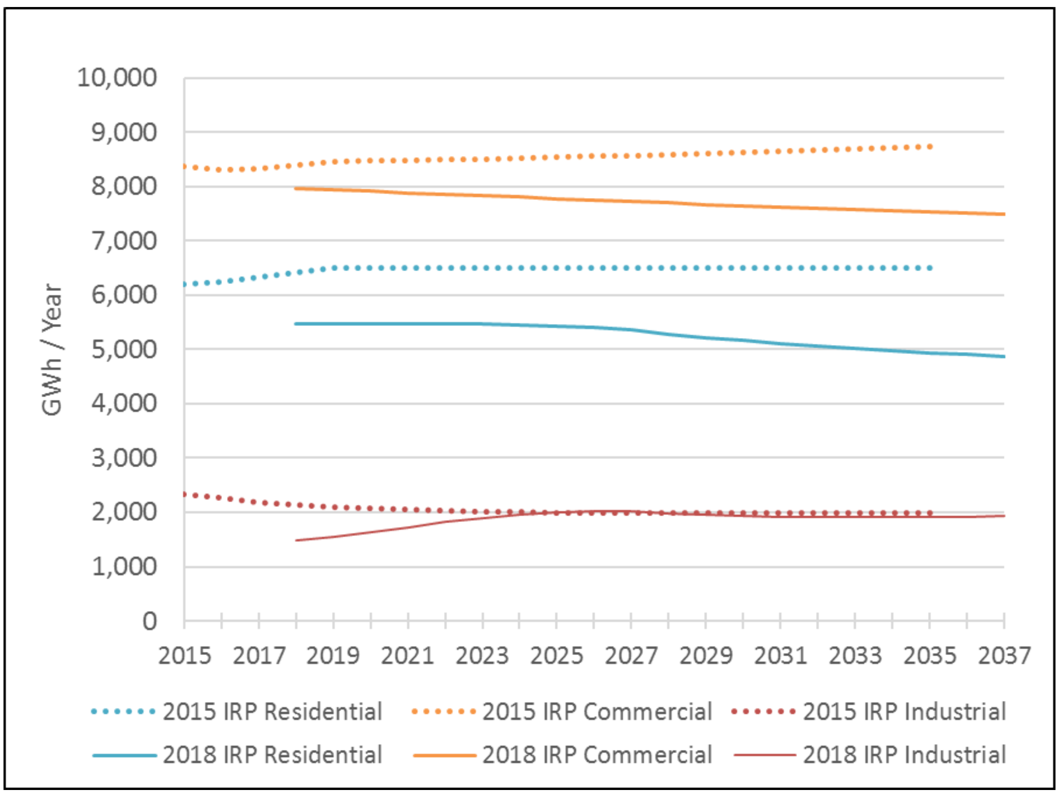
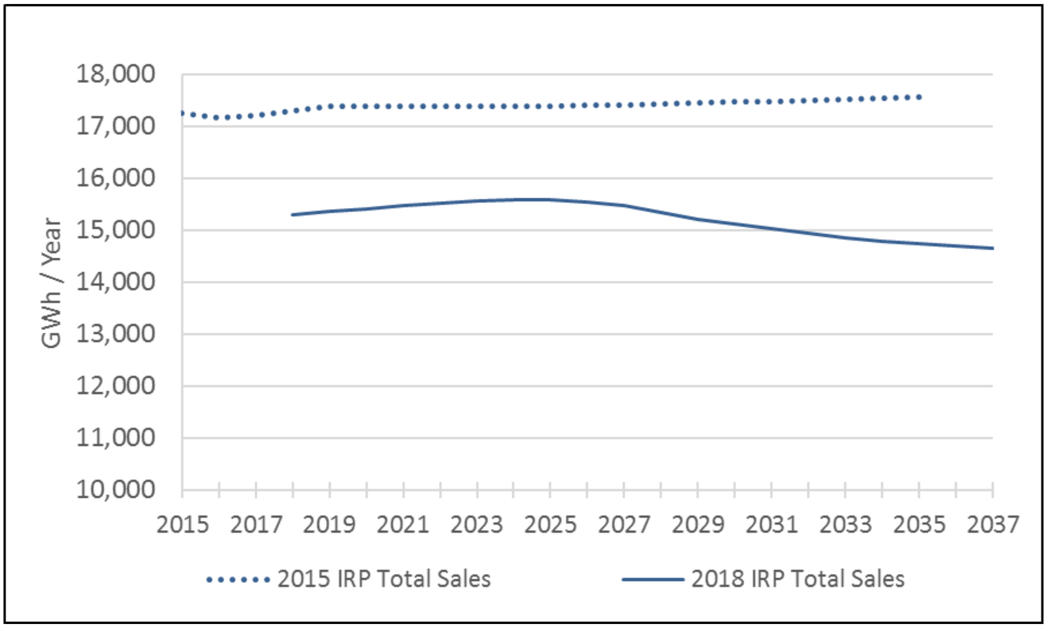


Exhibit 3-21: Comparison of 2015 versus 2018 IRP Forecasted Total Energy Sales

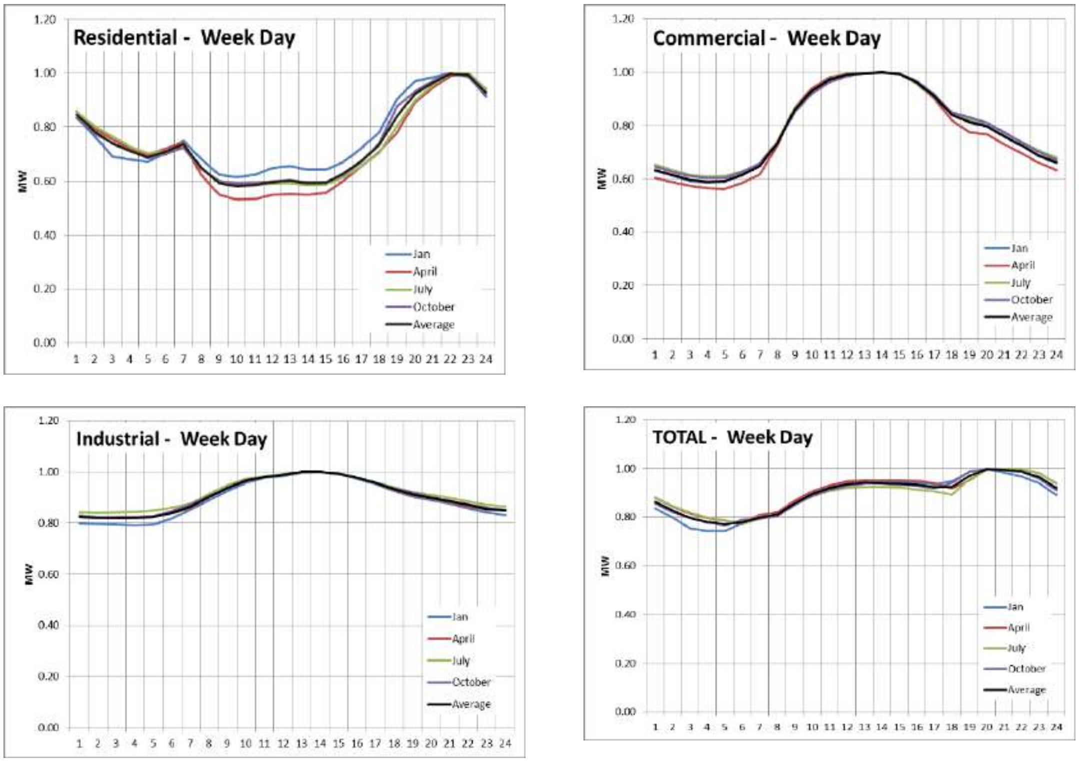


3.1.8 Long Term Peak Demand Forecast

To estimate the peak demand associated with the energy forecast the expected load factors (i.e. the ratio of average demand to the peak demand) for each customer class was assessed along with the percentage of their peak demand that occurs at the time of the system peak (called Customer Class Coincidence Factor – CCCF – or Contribution to the Peak Factor). In principle, these factors would ordinarily be determined monthly, consistent with the monthly detail of the energy forecast and include an analysis of load factors and coincident factors over multiple years. However, for this study, a single annual average load factor value was used for each class due to the fact that: a) there was not a significant change in the hourly load shapes for the relevant customer classes across the year, b) the load factor can be volatile unless averages are used due to its dependence on the measured peak, c) only one-year worth of hourly load data by customer class was available. The inclusion of a stochastic distribution of energy forecasts, discussed in later sections of this report, serves to drive a large range of forecasted peak demand.

Exhibit 3-18 shows the normalized load shapes for the main customer classes (residential, commercial and industrial) that constitute the vast majority of the forecasted energy consumption as well as the system total. As can be observed, unlike the mainland U.S. where there are large changes in the shape from summer to winter, the Puerto Rico load shapes show little seasonal variation (residential shows the greatest variation). An average annual load factor represents a reasonable method to represent each customer class. Exhibit 3-18 also illustrates that there are two peaks a day, the first in the daytime hours driven by commercial and industrial loads and the second an evening peak driven by the residential load. The evening peak is the higher of the two daily peaks. Thus, the residential customers peak coincides with the system peak (CCCF =1) while the industrial and commercial customers have a load below their respective class level peak loads at the time of the system peak load (CCCF < 1).

Exhibit 3-22. Normalized Load Shapes for main Customer Classes and System Total



Source Workpaper: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm

Based on the hourly information provided by PREPA, Siemens estimated the Customer Class Load Factors and Customer Class Coincidence Factors (% of the Customer Class peak at the time of the System Peak) shown in Exhibit 3-19.

Exhibit 3-23. Selected Load Factors and Customer Class Coincidence Factor

Customer Class	Customer Class Load Factor %	Customer Class Coincidence Factor %
Residential	66.9%	100%
Commercial	70.2%	70%
Industrial	81.2%	85%
Lighting	49.3%	100%
Other	73.6%	80%
Agriculture	46.8%	32%

Source Workpaper: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm

Using the values above and the forecasted energy consumption by customer class, the demand at the time of system peak can be forecasted. To this forecast peak load the following elements of load were added:

a) The effect of the technical transmission and distribution technical loses using a correction to convert energy losses into capacity losses based on the load factor[15].
b) The non-technical losses using same load factor and CCCF values as the residential load.
c) PREPA's own consumption using an estimated load factor based on historical values.
d) The effects of the consumption on the generating plants auxiliary services.

Exhibit 3-20 shows the energy demand and peak demand for generation, inclusive of the factors indicated above (technical and non-technical losses, auxiliary demand and PREPA's own use). Exhibit 3-20 does not include the impact of future energy efficiency (EE), demand response programs or DG. It should be noted that while DG is modeled separately as a source, it does have an impact in reducing the T&D technical losses and this is accounted for in the final forecast together with the impacts of EE, as is discussed later in this report. Demand Response is a resource used to provide reserves and it does not affect the load forecast.

Peak demand (before EE) is projected to decline by 0.24% per year. The lower rate of peak growth relative to the energy demand is a consequence of more modest growth in the residential demand compared to commercial demand and the corresponding contribution of each class to system peak demand. Commercial load peaks during the day, while the residential load peaks in the evening (sometimes very late), the latter driving the system peak. A reduction in residential load results in a reduction in the evening peak and an increase in the overall system load factor.

[15] Capacity Losses % = (Energy Losses %) / (0.3+0.7*LF)

Exhibit 3-24. Gross Generation

Fiscal Year	Energy (GWh)	Peak Demand (MW)	Load Factor (%)
2019	18,353	2,791	75.1%
2020	18,417	2,799	75.1%
2021	18,471	2,805	75.2%
2022	18,547	2,815	75.2%
2023	18,615	2,823	75.3%
2024	18,666	2,829	75.3%
2025	18,691	2,831	75.3%
2026	18,691	2,830	75.4%
2027	18,644	2,822	75.4%
2028	18,567	2,810	75.4%
2029	18,399	2,785	75.4%
2030	18,264	2,765	75.4%
2031	18,146	2,748	75.4%
2032	18,037	2,731	75.4%
2033	17,938	2,716	75.4%
2034	17,851	2,703	75.4%
2035	17,775	2,692	75.4%
2036	17,711	2,682	75.4%
2037	17,657	2,673	75.4%
2038	18,353	2,666	75.4%
CAGR	**-0.22%**	**-0.24%**	

Note: Forecast includes technical and non-technical losses, auxiliary demand and PREPA's own use. The forecast does not include the impact of future energy efficiency and/or demand response programs.
Source Workpaper: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm

As shown below, considering the impact of EE on Peak demand, the demand is projected to decline by 2.14% per year. Note that there is decline in the load factor over the period of the forecast.

Exhibit 3-25. Gross Generation after EE

Fiscal Year	Energy (GWh)	Peak (MW)	Load Factor (%)
2019	18,324	2,791	74.9%
2020	17,829	2,713	75.0%
2021	17,529	2,669	75.0%
2022	17,251	2,628	74.9%
2023	16,964	2,586	74.9%
2024	16,659	2,541	74.9%
2025	16,375	2,503	74.7%
2026	16,066	2,462	74.5%
2027	15,708	2,414	74.3%
2028	15,320	2,362	74.0%
2029	14,839	2,297	73.7%
2030	14,390	2,237	73.4%
2031	13,958	2,179	73.1%
2032	13,533	2,122	72.8%
2033	13,118	2,067	72.5%
2034	12,713	2,013	72.1%
2035	12,377	1,970	71.7%
2036	12,052	1,930	71.3%
2037	11,737	1,890	70.9%
2038	11,429	1,852	70.5%
CAGR	**-2.45%**	**-2.14%**	

Source Workpaper: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm

Considering the effect of customer owned generation there is a limited impact on the peak load as this is a night peak and most of the customer owned generation is photovoltaic. However, the exhibit below shows the impact of CHP assuming that in aggregate they are dispatched at 90% of the installed capacity at the time of the peak.

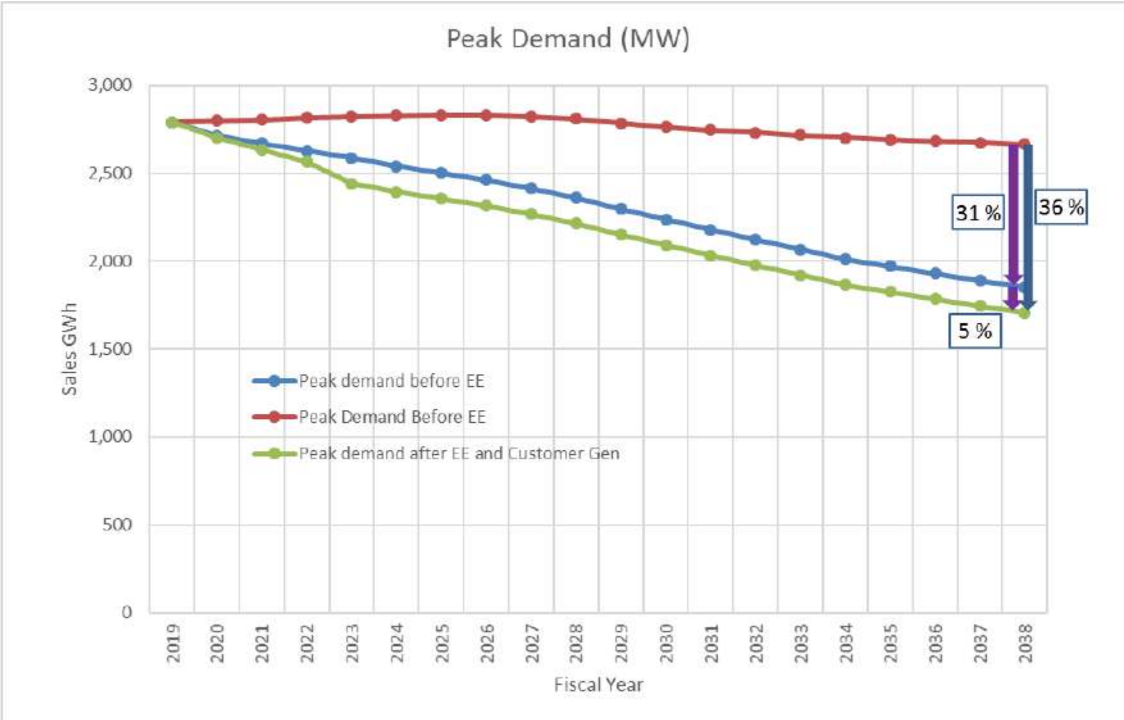
Exhibit 3-26. Gross Generation after EE and Customer Owned Generation

Fiscal Year	Energy (GWh)	Peak (MW)	Load Factor (%)
2019	18,196	2,791	74.4%
2020	17,410	2,703	73.5%
2021	16,876	2,632	73.2%
2022	16,028	2,564	71.4%
2023	15,692	2,440	73.4%
2024	15,333	2,395	73.1%
2025	14,996	2,357	72.6%
2026	14,630	2,316	72.1%
2027	14,211	2,268	71.5%
2028	13,755	2,216	70.8%
2029	13,209	2,151	70.1%
2030	12,687	2,091	69.3%
2031	12,179	2,033	68.4%
2032	11,670	1,976	67.4%
2033	11,174	1,921	66.4%
2034	10,682	1,867	65.3%
2035	10,255	1,825	64.2%
2036	9,831	1,784	62.9%
2037	9,422	1,744	61.7%
2038	9,012	1,706	60.3%
CAGR	-3.63%	-2.56%	

Source Workpaper: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm

Finally, as can be observed below the peak demand is projected to drop by 31 % due to the effects of EE by 2038 and by 36 % when the effects of customer owned generation are added.

Exhibit 3-27. Comparison Peak Demand before and after EE & Customer Owned Generation

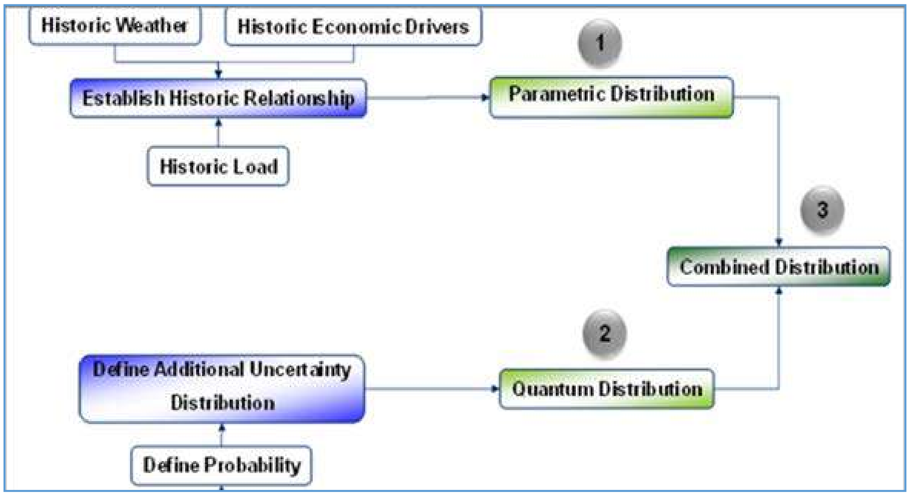


Source Workpaper: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm

3.1.9 Stochastic Distribution

To generate Scenarios for energy growth, Siemens developed statistical distributions based on deterministic energy forecasts. The process involves two steps: the first involves developing parametric distributions around key fundamental variables that could present more volatility in the future (weather and economic performance in Puerto Rico). Siemens utilized historical data to develop 2,000 Scenarios for weather and GNP that were fed into the econometric regression model to determine 2,000 iterations of average and high energy growth. The second step involves developing quantum distributions, which incorporate future uncertainties not captured by the historical data. The overall process is summarized by the flow chart in Exhibit 3-19 below.

Exhibit 3-28. Stochastic Process for Energy Forecasts



3.1.10 Parametric Distributions

The development of stochastics is based on building probability distributions around the deterministic energy forecast. To produce probability distributions of the energy forecast, Siemens propagates three independent random paths: CDD, GNP, and a residual.

- To produce reasonable weather data projections, Siemens sampled 17-years of monthly historical weather data based on CDD for 2000-2017.
- GNP is assumed to follow a Geometric Brownian Motion. This means that there exists a normal distribution with constant mean and variance that describes how the GNP could behave at any time in the future. The process is developed using historical quarterly GNP data for 2000-2017.
- Finally, to account for unexplained variation in the observed data, Siemens adds a normally distributed residual with mean zero and standard deviation equal to the root mean squared error from a stepwise regression.

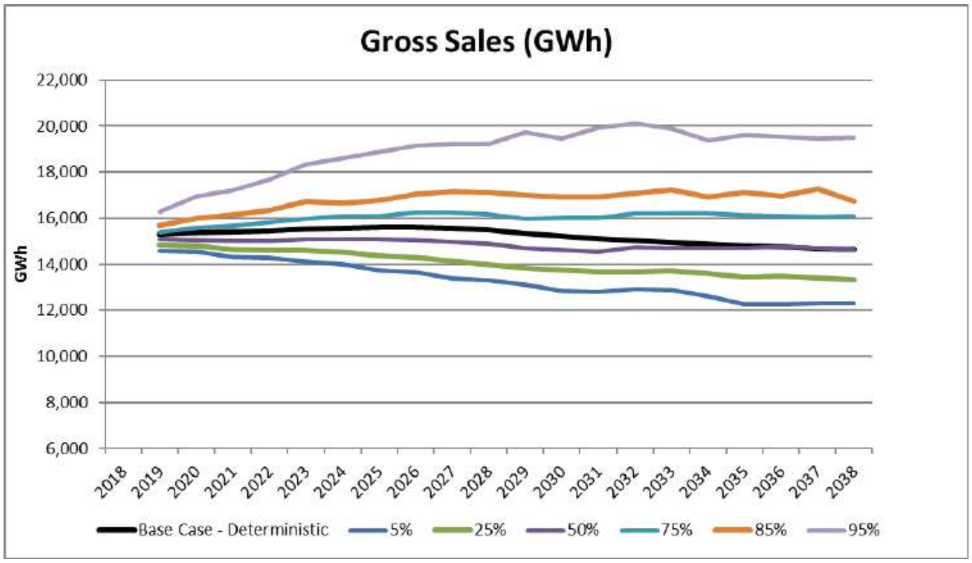
Based on historical volatility, 2,000 distributions of these variables are developed and used in the stepwise regression model to develop an intermediate distribution of average and peak energy forecast distributions.

3.1.11 Quantum Distribution: Additional Variability

It is Siemens' opinion that future energy demand may differ substantially from past energy demand. To account for this possibility, Siemens adds an additional "Quantum Distribution" to its empirically derived distribution. The 5th percentile of this distribution reflects a low growth Scenario (i.e. higher degree of DSM and DG penetration). The upper tail of this distribution (95th Percentile) is weighted to match Siemens' analysis of historical high periods of energy growth and to capture other events such as higher penetration of air conditioning loads and rising demand from electric vehicles. Using these high and low growth Scenarios, Siemens generates a distribution of energy forecasts using statistical techniques. This distribution is superimposed on the parametric distribution obtained in the step discussed above. The resulting distribution is considered the final average and peak energy forecast distribution (2,000 iterations).

Exhibit 3-20 shows an illustrative stochastic distribution of gross sales for planning purposes.

Exhibit 3-29. Stochastic Distribution of Gross Sales



Note: The sales forecasts reflect gross energy sales inclusive of existing EE programs. It does not include loses, PREPA's own use and auxiliary demand neither any future incremental EE and/or demand response programs.

The mean path corresponds to the average of 2,000 iterations of combinations of the stochastic input drivers. The percentile bands are not energy paths but instead represent the likelihood that the sales could be at or below that level in a given year. For example, in 2025 there is a 95% likelihood that energy sales will be at or below 18,885 MWh. Also, in 2025, there is a 5% chance that energy sales will be at or below 14,352 MWh.

Based on its assessment of the results of the stochastic distributions, Siemens chose to use the 25th percentile as the low case and the 85th percentile as the high case for all Scenarios. In general, the 75th and the 25th percentile represent approximately one standard deviation above and below the mean on a normal distribution. However, load tends to follow a log normal distribution, which tends to have an upward bias. As result, Siemens considered that using the 85th percentile would be more reasonable for the high case.

The 85th and 25th percentiles do not represent extreme cases either but a reasonable high and low forecast for planning purposes. The extreme high and low would typically be defined by the 95th percentile and 5th percentile, respectively.

To describe the factors that could give rise to the extreme high and low forecasts mathematically obtained above, Siemens developed and very optimistic Scenario and a very pessimistic Scenario for the macroeconomic parameters driving the forecast: GNP and population.

The very optimistic case assumes that the structural reforms in Puerto Rico are highly successful and the GNP after hitting a low in 2018 bounces back at a rate 50% faster than Moody's forecast for two years as federal funds are invested in the island. From 2020 onwards, the Puerto Rico economy recovers to its pre-2006 potential and the GNP grows at 75% of the US GNP forecast growth rate – see Exhibit 3-21. Consistent with this economic

outlook, there is initially a population drop following the U.S. Census forecast until 2019 and from 2020 onwards, as the Puerto Rico economy starts to grow, the population outflow reduces to only 25% of the yearly attrition in the U.S. Census forecast – see Exhibit 3-22.

The very pessimistic case, assumes that the structural reforms do not take place and there is limited federal funds invested in the island, resulting in a continuation of the GNP decline at 1% per year in line with the historical post 2006 decline. Consistent with this outlook the population decline accelerates and after an initial drop in line with FOMB forecasts, from 2019 onwards it declines at 1.5 times yearly attrition in this forecast.

Exhibit 3-30. GNP Scenarios

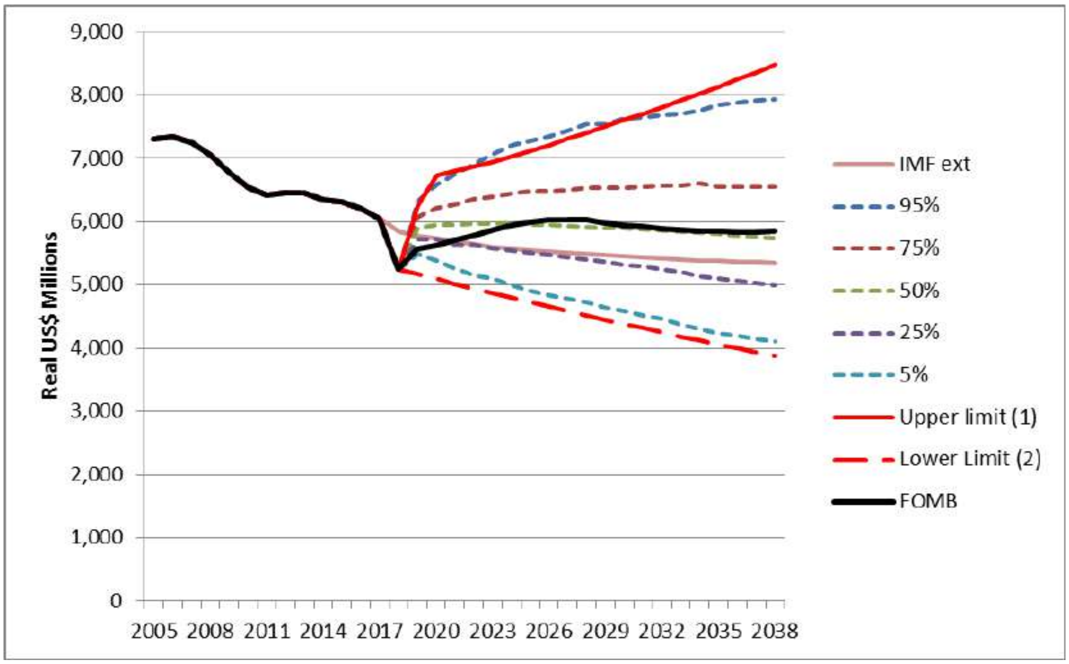
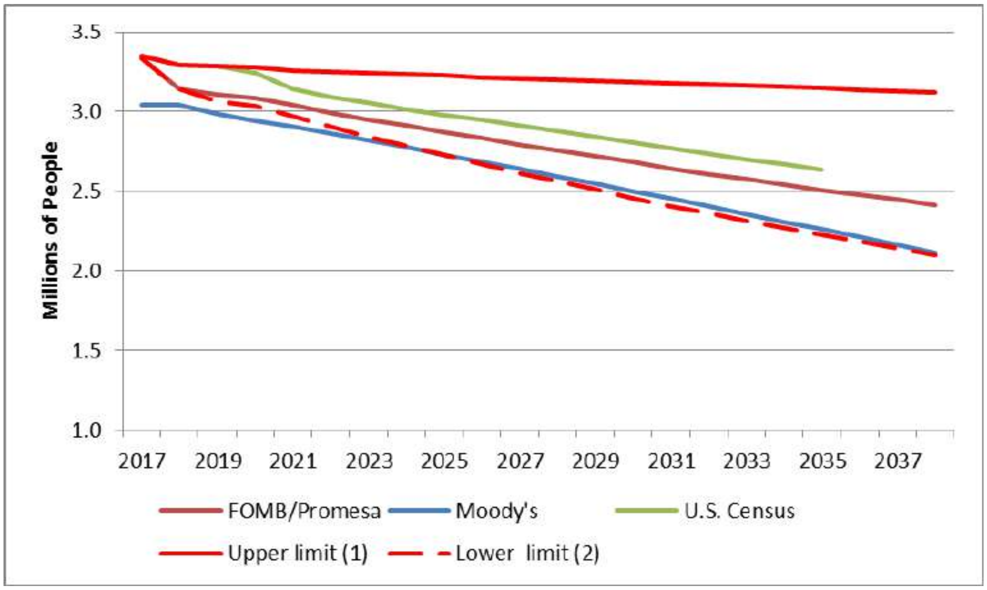


Exhibit 3-31. Population Scenarios

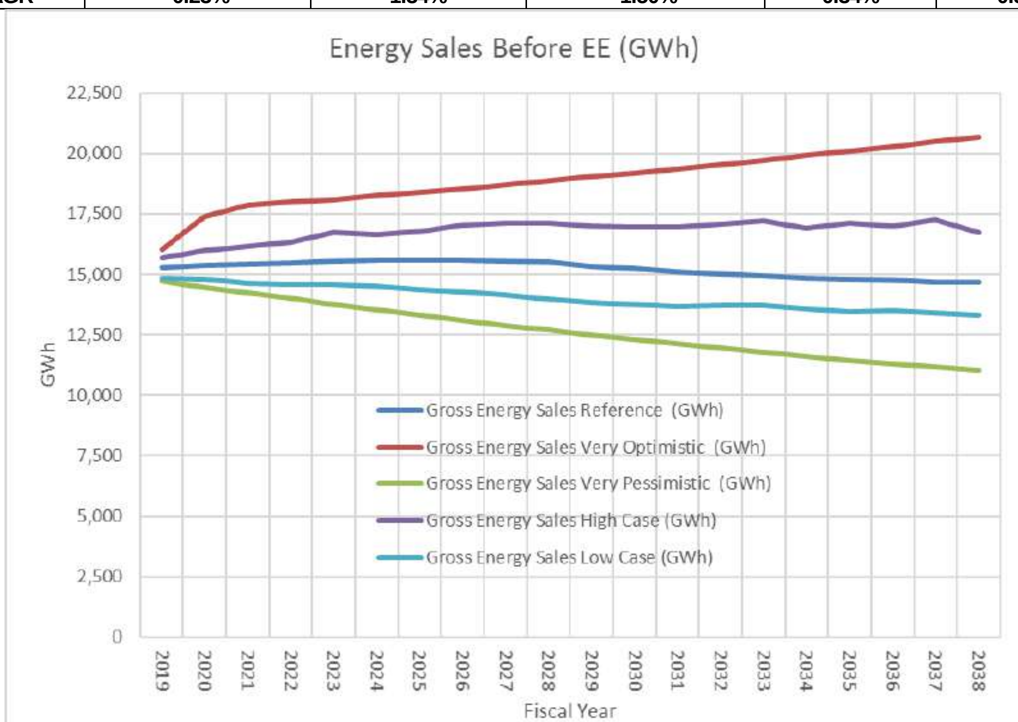


The resulting gross sales forecasts for the Upper and Lower limits are shown in Exhibit 3-23. In the high case Scenario, gross energy sales increase at 1.34% per-year, with sales reaching 20,672 GWh by 2038 – 41% higher than the reference case. In the low case Scenario, gross energy sales decline at 1.50% per-year reaching 11,033 GWh by 2038, 75% below the reference case level. The industrial customer class has the most upside or downside potential driven by changes in the GNP and/or population from all three classes, with sales growing at 5.6% per-year in the high case or declining at 5.2% per-year in the low case. The forecasts below do not include the impact of new energy efficiency programs.

Exhibits 3-31 and 3-32 shows the impact on the sales forecast of the Energy Efficiency the first and the customer owned generation the second.

Exhibit 3-32. Gross Sales Forecast Scenarios – High and Low Cases

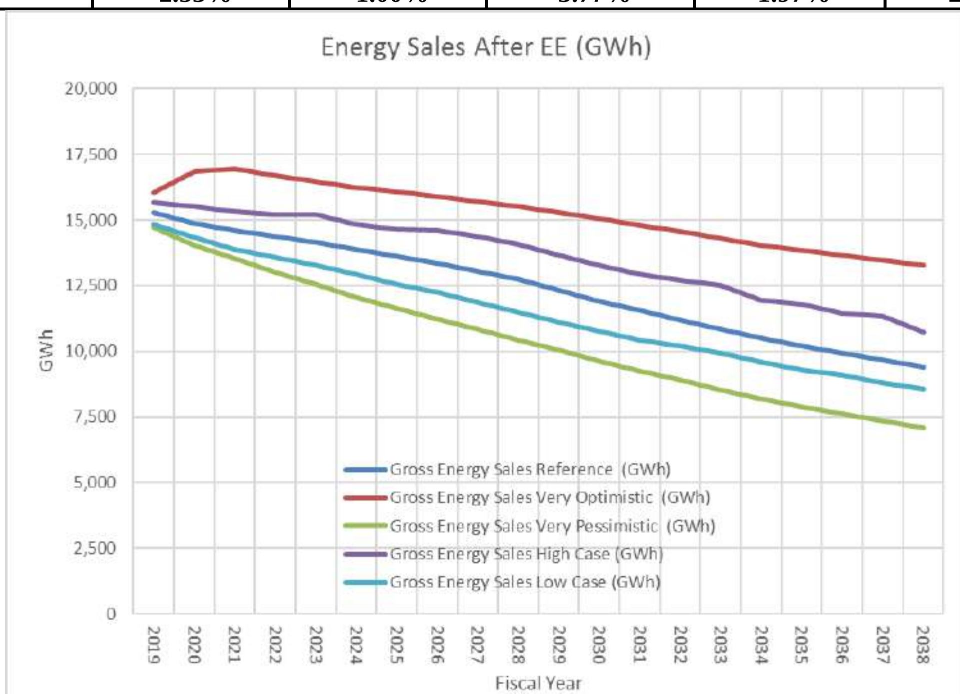
Fiscal Year	Gross Energy Sales Reference (GWh)	Gross Energy Sales Very Optimistic (GWh)	Gross Energy Sales Very Pessimistic (GWh)	Gross Energy Sales High Case (GWh)	Gross Energy Sales Low Case (GWh)
2019	15,301	16,043	14,703	15,670	14,844
2020	15,357	17,400	14,470	16,001	14,811
2021	15,403	17,869	14,257	16,166	14,636
2022	15,470	17,976	14,015	16,358	14,596
2023	15,530	18,102	13,776	16,730	14,588
2024	15,574	18,239	13,545	16,642	14,514
2025	15,595	18,385	13,325	16,755	14,352
2026	15,596	18,540	13,112	17,024	14,292
2027	15,554	18,699	12,901	17,136	14,148
2028	15,487	18,863	12,695	17,114	13,989
2029	15,341	19,030	12,498	16,998	13,831
2030	15,223	19,200	12,304	16,939	13,740
2031	15,120	19,372	12,118	16,932	13,664
2032	15,025	19,547	11,939	17,078	13,690
2033	14,939	19,725	11,765	17,235	13,702
2034	14,862	19,906	11,597	16,923	13,582
2035	14,796	20,091	11,439	17,113	13,435
2036	14,741	20,280	11,295	16,976	13,476
2037	14,694	20,474	11,160	17,270	13,390
2038	14,654	20,672	11,033	16,719	13,323
CAGR	**-0.23%**	**1.34%**	**-1.50%**	**0.34%**	**-0.57%**



Source Workpapers: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm, Load Forecast by Region PREPA EE_DG_2018 IRP High Case35 pct EE 050319.xlsm and Load Forecast by Region PREPA EE_DG_2018 IRP Low Case35 pct EE 050319.xlsm

Exhibit 3-33. Sales Forecast Scenarios after EE – High and Low Cases

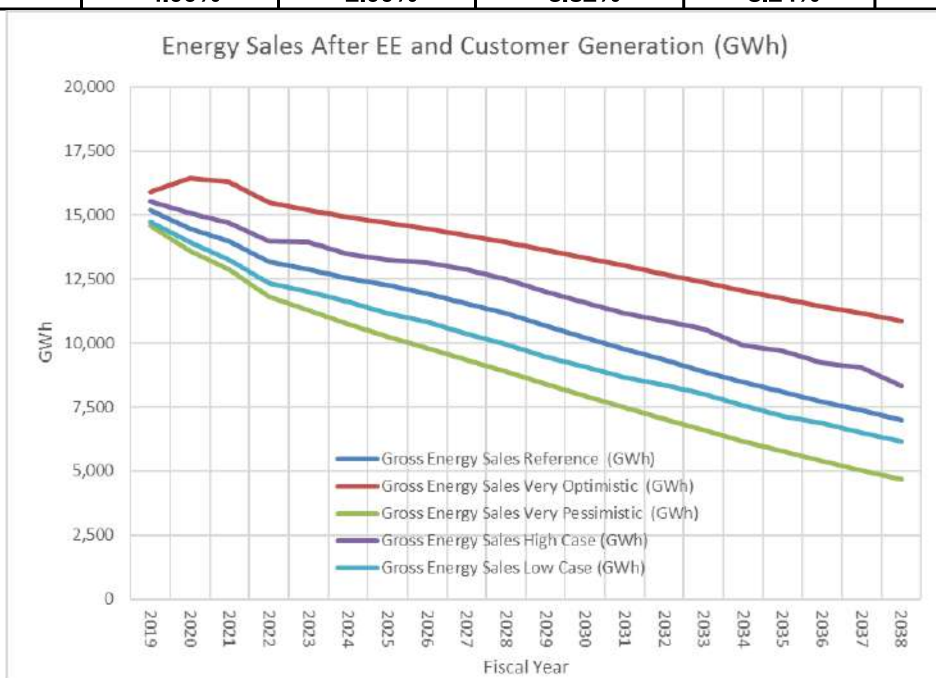
Fiscal Year	Gross Energy Sales Reference (GWh)	Gross Energy Sales Very Optimistic (GWh)	Gross Energy Sales Very Pessimistic (GWh)	Gross Energy Sales High Case (GWh)	Gross Energy Sales Low Case (GWh)
2019	15,301	16,043	14,703	15,669	14,845
2020	14,874	16,852	14,015	15,496	14,346
2021	14,617	16,956	13,529	15,339	13,890
2022	14,379	16,708	13,026	15,202	13,568
2023	14,133	16,474	12,537	15,223	13,278
2024	13,872	16,245	12,064	14,821	12,929
2025	13,628	16,066	11,645	14,640	12,544
2026	13,364	15,887	11,236	14,585	12,249
2027	13,057	15,697	10,830	14,382	11,879
2028	12,725	15,497	10,431	14,058	11,496
2029	12,311	15,271	10,030	13,638	11,103
2030	11,926	15,041	9,640	13,268	10,767
2031	11,556	14,805	9,262	12,938	10,446
2032	11,193	14,560	8,894	12,719	10,201
2033	10,838	14,309	8,536	12,500	9,942
2034	10,492	14,052	8,188	11,944	9,590
2035	10,207	13,858	7,892	11,801	9,270
2036	9,932	13,662	7,611	11,434	9,082
2037	9,665	13,465	7,341	11,355	8,810
2038	9,405	13,267	7,082	10,728	8,554
CAGR	**-2.53%**	**-1.00%**	**-3.77%**	**-1.97%**	**-2.86%**



Source Workpapers: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm, Load Forecast by Region PREPA EE_DG_2018 IRP High Case35 pct EE 050319.xlsm and Load Forecast by Region PREPA EE_DG_2018 IRP Low Case35 pct EE 050319.xlsm

Exhibit 3-34. Sales Forecast Scenarios after EE and Customer Generation – High and Low Cases

Fiscal Year	Gross Energy Sales Reference (GWh)	Gross Energy Sales Very Optimistic (GWh)	Gross Energy Sales Very Pessimistic (GWh)	Gross Energy Sales High Case (GWh)	Gross Energy Sales Low Case (GWh)
2019	15,173	15,915	14,575	15,541	14,717
2020	14,455	16,433	13,596	15,077	13,927
2021	13,963	16,303	12,876	14,686	13,237
2022	13,156	15,485	11,804	13,980	12,345
2023	12,861	15,201	11,265	13,951	12,005
2024	12,546	14,919	10,738	13,495	11,603
2025	12,250	14,687	10,266	13,261	11,165
2026	11,928	14,451	9,800	13,149	10,813
2027	11,560	14,199	9,333	12,885	10,382
2028	11,160	13,933	8,866	12,494	9,931
2029	10,681	13,641	8,400	12,008	9,472
2030	10,223	13,338	7,937	11,565	9,064
2031	9,776	13,025	7,482	11,158	8,666
2032	9,329	12,697	7,031	10,855	8,337
2033	8,894	12,365	6,592	10,556	7,999
2034	8,461	12,020	6,156	9,912	7,559
2035	8,085	11,736	5,770	9,679	7,148
2036	7,711	11,441	5,390	9,213	6,861
2037	7,350	11,151	5,027	9,041	6,495
2038	6,989	10,850	4,665	8,311	6,137
CAGR	**-4.00%**	**-2.00%**	**-5.82%**	**-3.24%**	**-4.50%**



Source Workpapers: Load Forecast by Region PREPA 2018 IRP Base Case Revised 35 pct EE 050319.xlsm, Load Forecast by Region PREPA EE_DG_2018 IRP High Case35 pct EE 050319.xlsm and Load Forecast by Region PREPA EE_DG_2018 IRP Low Case35 pct EE 050319.xlsm

3.1.12 Base Case Load Forecast Selection

The Reference Case was developed considering the expected value of the underlying explanatory variables and as can be observed above it corresponds to the median of outcomes. This case was used in the analysis together with the sensitivities to High and Low load forecast.

Part
4

Existing Resources

4.1 Existing Generation Resources and Distributed Generation

Siemens reviewed cost and technical characteristics and operating status on PREPA's existing generation resources and Power Purchase and Operating Agreements (PPOAs) as inputs to the IRP. The thermal supply-side resources section of this report (Appendix 5 – New and Existing Supply-Side Resources Supplemental Data) includes a review of the operating characteristics of the generation units along with their operating costs.

On the other hand, Part 6 – New Resources Options of this report presents the new resources considered in the IRP and Appendix 4 – Demand Side Resources presents a discussion of the demand side resources including distributed generation, energy efficiency, demand response, and CHP (Combined Heat and Power).

4.2 Summary of Current PREPA and Contracted Supply Resources

The Exhibits that follow provide a comprehensive listing of parameters and historical performance of the supply resources and, including capacity factors, heat rates and units planned for retirement within the next ten years.

Exhibit 4-1. Summary of Existing Plant Characteristics and performance

	2018 Data						Capacity Factor											
Plant Name	Available Capacity (MW)	Net Generation (MWh)	Average Rate Heat (Btu/ kWh)	Fuel Cost $Mmbtu	$/O&M per kWh	Total $O&M plus fuel	2013	2014	2015	2016	2017	2018	Nameplate Capacity (MW)	Resource Type	Fuel Type	Ownership	Location	Commercial Operation Date
Aguirre Steam 1&2	900	2,945,857	10,693	12.52	0.01	0.14	49%	44%	46%	29%	33%	37%	900	Oil	Fuel #6	PREPA	Salinas	1975
Aguirre CCGT 1&2	592	218,653	13,882	17.10	0.04	0.27	5%	12%	12%	12%	9%	4%	609	Oil	Fuel #2	PREPA	Salinas	1977
Aguirre GT	42	1,642	13,688	11.73	0.20	0.40	0%	0%	3%	1%	1%	0%	45	Oil	Fuel #2	PREPA	Salinas	1972
San Juan Steam 7, 8, 9 & 10	400	557,340	8,957	11.41	0.01	0.14	41%	46%	43%	36%	23%	16%	400	Oil	Fuel #6	PREPA	San Juan	1965 to 1969
San Juan CCGT 5 & 6	440	2,323,272	13,688	16.73	0.01	0.14	45%	25%	37%	59%	57%	60%	470	Oil	Fuel #2	PREPA	San Juan	2008
Costa Sur Steam 3 & 4	170	0	11,898	10.12	0.00	0.00	1%	0%	6%	2%	0%	0%	165	Oil	Fuel #6	PREPA	Guayanilla	1962 & 1963
Costa Sur Steam 5 & 6	782	3,145,699	11,898	9.01	0.01	0.11	52%	61%	66%	63%	43%	46%	820	Oil	NG & Fuel #6	PREPA	Guayanilla	1972 & 1973
Costa Sur GT	42	0	13,688	0.00	0.00	0.00	1%	1%	4%	2%	1%	0%	45	Oil	Fuel #2	PREPA	Guayanilla	1972
Culebra	2	9,344	0	0.00	0.00	0.00	1%	0%	0%	0%	4%	53%	2	Diesel	Diesel	PREPA	Culebra	1972
Daguao	42	50,938	13,688	16.19	0.31	0.61	0%	1%	3%	2%	11%	14%	45	Oil	Fuel #2	PREPA	Ceiba	1972
Jobos	42	703	13,688	12.20	0.09	0.19	0%	1%	3%	1%	3%	0%	45	Oil	Fuel #2	PREPA	Guayama	1973
Mayaguez Plant 1,2 ,3 & 4	220	124,872	13,688	17.20	0.18	0.37	7%	9%	6%	3%	7%	6%	220	Oil	Fuel #2	PREPA	Mayagüez	2009
Palo Seco Steam 1,2, 3 & 4	602	932,865	11,174	11.74	0.02	0.15	40%	21%	20%	28%	9%	18%	597	Oil	Fuel #6	PREPA	Toa Baja	1960, 1961 & 1970
Palo Seco GT	126	121,137	13,688	16.03	0.24	0.48	1%	7%	8%	7%	16%	11%	134	Oil	Fuel #2	PREPA	Toa Baja	1972 & 1973
Vega Baja	42	5,013	13,688	15.78	0.23	0.47	0%	1%	0%	1%	3%	1%	45	Oil	Fuel #2	PREPA	Vega Baja	1971
Vieques	7	20,774	0	22.73	0.00	0.00	0%	0%	0%	0%	0%	36%	7	Diesel	Diesel	PREPA	Vieques	2004
Yabucoa	42	16,020	13,688	14.94	0.29	0.59	0%	0%	6%	5%	4%	4%	45	Oil	Fuel #2	PREPA	Yabucoa	1971
Cambalache GT 1, 2 & 3	248	81,788	13,143	16.40	0.05	0.27	3%	5%	8%	5%	9%	4%	248	Oil	Fuel #3	PREPA	Arecibo	1977
Toro Negro 1	9	1,899	-	-	-	-	13%	2%	1%	5%	5%	3%	9	Hydroelectric	Water	PREPA	Villalba	1937
Toro Negro 2	2	0	-	-	-	-	9%	6%	7%	0%	3%	0%	2	Hydroelectric	Water	PREPA	Orocovis	1937
Garzas 1	7	1,501	-	-	-	-	1%	0%	0%	0%	0%	2%	7	Hydroelectric	Water	PREPA	Peñuelas	1941
Garzas 2	5	0	-	-	-	-	1%	0%	0%	0%	0%	0%	5	Hydroelectric	Water	PREPA	Peñuelas	1941
Yauco 1	25	0	-	-	-	-	11%	8%	0%	0%	0%	0%	20	Hydroelectric	Water	PREPA	Yauco	1956
Yauco 2	9	7,235	-	-	-	-	13%	9%	9%	10%	9%	9%	8	Hydroelectric	Water	PREPA	Yauco	1954
Dos Bocas	15	27,203	-	-	-	-	27%	22%	19%	30%	23%	21%	18	Hydroelectric	Water	PREPA	Utuado	1942-1945
Caonillas 1	18	0	-	-	-	-	6%	15%	14%	13%	6%	0%	18	Hydroelectric	Water	PREPA	Arecibo	1952
Río Blanco	5	0					0.01%	-	0.01%	-	-	-	5	Hydroelectric	Water	PREPA	Naguabo	1930
EcoEléctrica	507	2,999,834	-	-	-	-	80%	83%	66%	75%	62%	68%	507	Natural Gas	Natural Gas	Purchase	Peñuelas	1999
AES	454	2,505,636	-	-	-	-	86%	92%	82%	87%	58%	63%	454	Coal	Coal	Purchase	Guayama	2002
Windmar Renewable	2	4,424	-	-	-	-	21%	26%	28%	25%	22%	24%	2	Photovoltaic	Sun	Purchase	Ponce	9/1/2011
San Fermín Solar	21	10,063	-	-	-	-	-	1%	18%	20%	15%	5%	20	Photovoltaic	Sun	Purchase	Loíza	12/1/2015
Horizon Energy Inc.	10	5,295	-	-	-	-	-	-	17%	27%	21%	6%	10	Photovoltaic	Sun	Purchase	Salinas	11/1/2016
AES Ilumina	20	23,923	-	-	-	-	21%	23%	23%	22%	17%	14%	20	Photovoltaic	Sun	Purchase	Guayama	11/1/2012
Oriana Energy Solar	45	21,018	-	-	-	-	-	-	-	3%	17%	5%	45	Photovoltaic	Sun	Purchase	Isabela	9/1/2016
Humacao Solar (Fonroche)	20	5,703	-	-	-	-	-	-	-	0%	3%	3%	20	Photovoltaic	Sun	Purchase	Humacao	12/1/2016
Windamr Solar (Cotto Laurel)	10	10,417	-	-	-	-	-	-	-	1%	6%	12%	10	Photovoltaic	Sun	Purchase	Ponce	11/1/2016
Punta Lima Wind	26	0	-	-	-	-	25%	24%	26%	22%	17%	0%	26	Wind	Wind	Purchase	Naguabo	12/1/2012
Pattern Energy	75	108,072	-	-	-	-	18%	25%	27%	22%	17%	16%	75	Wind	Wind	Purchase	Santa Isabel	12/1/2012
Landfill Gas Technologies	4	2,401	-	-	-	-	-	-	1%	20%	18%	7%	4	Landfill Gas	Methane Gas	Purchase	Fajardo	10/1/2016
Landfill Gas Technologies	2	8,171	-	-	-	-	-	-	-	-	23%	39%	2	Landfill Gas	Methane Gas	Purchase	Toa Baja	10/1/2016
Total		16,298,716																

*Excluded the generation from the US Army Corps of Engineers turbines.

Workpaper Source: Plant Data and CF 2013 to 2018.xlsx

Exhibit 4-2. Estimated Retirement of Units to be Retired in Next 10 Years

Unit	Available Capacity (MW)	Commercial Operation Date (Yr.)	Planned Retirement (Yr.)	Estimated Remaining Useful Life after 2019	Reason for Retirement
AES_1	227	2002	2027	8	PPA Expiration
AES_2	227	2002	2027	8	PPA Expiration
Aguirre 2 CCGT	260	1977	2025	6	Expected Retirement Due to Age
Aguirre STEAM 1	450	1975	2019	0	Planned Retirement Due to Age, Condition and Cost of MATS Compliance
Aguirre STEAM 2	450	1975	2019	0	Planned Retirement Due to Age, Condition and Cost of MATS Compliance
Costa Sur 5	410	1972	2020	1	Planned Retirement Due to Age, Condition and Cost of MATS Compliance
Costa Sur 6	410	1973	2020	1	Planned Retirement Due to Age, Condition and Cost of MATS Compliance
Palo Seco 3	216	1961	2025	6	Expected Retirement Due to Age, Condition and Cost of MATS Compliance
Palo Seco 4	216	1970	2025	6	Expected Retirement Due to Age, Condition and Cost of MATS Compliance
San Juan 7	100	1965	2023	4	Expected Retirement Due to Age, Condition and Cost of MATS Compliance
San Juan 8	100	1969	2021	2	Expected Retirement Due to Age, Condition and Cost of MATS Compliance
San Juan 6 CCGT	200	2008	2025	6	Expected Retirement Due to Age and Unit Efficiency
GT Peakers	378	Various	2021	2	Planned End of Life Due to Age and Condition

Workpaper Source: Generation Remaining Life & Retirement Reason.xlsx

Exhibit 4-3. Average Annual Heat Rate of Fossil Units (2013 to 2018)

Plant Name	2018 Available Capacity (MW)	Average Annual Heat Rate (Btu / kWh) 2013	2014	2015	2016	2017	2018
Aguirre Steam 1 & 2	900	10,539	10,635	10,496	10,456	10,814	10,693
Aguirre CCGT 1 & 2	592	10,535	11,684	13,811	12,081	13,202	13,882
Aguirre GT	42	10,707	11,572	12,641	13,155	13,541	13,688
San Juan Steam 7, 8, 9 & 10	400	9,928	10,366	9,934	9,419	9,577	8,957
San Juan CCGT 5 & 6	440	10,707	11,572	12,641	13,155	13,541	13,688
Costa Sur Steam 3 & 4	170	10,740	10,775	10,884	11,078	0	11,898
Costa Sur Steam 5 & 6	782	10,707	10,775	10,884	11,078	11,617	11,898
Costa Sur GT	42	10,707	11,572	12,641	13,155	13,541	13,688
Daguao	42	10,707	11,572	12,641	13,155	13,541	13,688
Jobos	42	10,707	11,572	12,641	13,155	13,541	13,688
Mayaguez Plant 1, 2,3 & 4	220	10,707	11,572	12,641	13,155	13,541	13,688
Palo Seco Steam 1 ,2, 3 & 4	602	10,837	11,572	11,980	11,766	10,562	11,174
Palo Seco GT	126	10,707	11,572	12,641	13,155	13,541	13,688
Vega Baja	42	10,707	11,572	12,641	13,155	13,541	13,688
Yabucoa	42	10,707	11,572	12,641	13,155	13,541	13,688
Cambalache GT 1, 2 & 3	248	12,209	12,346	12,887	12,627	12,926	13,143

Workpaper Source: Plant Average Annual Heat Rate 2013 to 2018.xlsx

The Exhibit that follows summarizes PREPA's capital expenditures required to maintain its existing generation fleet.

Exhibit 4-4. Annual Historical Production Capital Expenditures ($ millions)

2013-14	2014-15	2015-16	2016-17	2017-18	5- Year Average
$75.72	$46.22	$49.85	$72.27	$37.59	$56.33

The planned capital expenditures for the production department for the next two years are provided in the workpaper "Proposed Capital Expenditures 2019 to 2020.xlsx". PREPA will need to continue maintaining existing units to preserve system reliability and resiliency until new resources become available.

4.2.1 IRP Modeling of PREPA's Existing Generation Facilities.

Siemens reviewed and discussed PREPA's existing generation resources, including the units' condition and operating status, with PREPA's staff. As a result of this review, 39 existing generation units, with a total capacity of 5,010 MW, were determined to be in acceptable operating condition for consideration as available resources in this IRP.

Exhibit 4-1 presents the operational parameters including technology (i.e., steam turbine [ST], simple cycle combustion turbines, referenced as gas turbines per PREPA conventions [GT], and combined cycle gas turbine [CC]), rated capacity[16], fuel type, heat rate, fixed operating and maintenance costs (FOM), and variable operating and maintenance costs (VOM) of the existing generation resources in 2018 dollars.

[16] The maximum capacities considered in the study are based on information provided by PREPA. These capacities are smaller than the nominal capacities in the case of San Juan 5 and 6 CC (nominal capacity of 220 MW each), Aguirre CC 1 and 2 (nominal capacity of 296 MW each), Mayagüez GT (nominal capacity of 55 MW each), and the hydro generation (nominal capacity of 105 MW). The total nominal capacity of existing PREPA generation resources is 5,213 MW.

Exhibit 4-5. PREPA Existing Units Included in the IRP

	Generation Units	Maximum Modeled Capacity (MW)	Fuel	Heat Rate at Max. Capacity (BTU/kWh)	FOM (2018 $/kW-year)	VOM (2018 $/MWh)
MATS Affected Units	Aguirre 1 ST	450	No. 6 fuel oil	9,600	32.04	2.25
	Aguirre 2 ST	450	No. 6 fuel oil	9,700	32.04	2.25
	Costa Sur 5 ST	410	Natural gas	9,747	35.96	2.72
	Costa Sur 6 ST	410	Natural gas	9,747	35.96	2.72
	Palo Seco 3 ST	216	No. 6 fuel oil	9,725	46.47	4.95
	Palo Seco 4 ST	216	No. 6 fuel oil	9,725	46.47	4.95
	San Juan 7 ST	100	No. 6 fuel oil	10,497	49.02	2.93
	San Juan 8 ST	100	No. 6 fuel oil	10,445	49.02	2.93
Combined Cycle	Aguirre 1 CC	260	Diesel	11,140	22.64	6.79
	Aguirre 2 CC	260	Diesel	11,140	22.64	6.79
	San Juan 5 CC	200	Diesel	7,625	27.40	2.22
	San Juan 6 CC	200	Diesel	7,853	27.40	2.22
Gas Turbine	Cambalache 2 GT	83	Diesel	11,549	24.44	5.52
	Cambalache 3 GT	83	Diesel	11,549	24.44	5.52
	Mayagüez 1 GT	50	Diesel	9,320	10.64	6.40
	Mayagüez 2 GT	50	Diesel	9,320	10.64	6.40
	Mayagüez 3 GT	50	Diesel	9,320	10.64	6.40
	Mayagüez 4 GT	50	Diesel	9,320	10.64	6.40
	Daguao 2 GTs	42	Diesel	14,400	26.54	20.19
	Palo Seco GT11 & GT12	42	Diesel	14,400	26.54	20.19
	Palo Seco GT21 & GT 22	42	Diesel	14,400	26.54	20.19
	Palo Seco GT31 & GT32	42	Diesel	14,400	26.54	20.19
	Aguirre GT21 & GT22	42	Diesel	14,400	26.54	20.19
	Costa Sur GT11 & GT12	42	Diesel	14,400	26.54	20.19
	Jobos GT11 & GT12	42	Diesel	14,400	26.54	20.19
	Yabucoa GT11 & GT12	42	Diesel	14,400	26.54	20.19
	Vega Baja GT11 & GT12	42	Diesel	14,400	26.54	20.19
Hydro	Hydro	34	Water	N/A	N/A	N/A
IPP Units	AES Coal 2 Units	454	Coal	9,791	79.46	7.23
	EcoEléctrica Plant	507	Natural gas	7,497	189.34	0.00
Total		**5,010**				

Source: PREPA, Siemens.

Note: while San Juan 7 & 8 are included in the model, and 9 & 10 were not, from a modeling perspective they are fully interchangeable. If PREPA determines that San Juan 9 is more reliable than one of the other units, it may be substituted without impacting model results.

It was jointly decided that 11 existing generation units, with a total capacity of 707 MW, were not in sufficient operational condition for inclusion as a generation resource in this IRP. A summary of the excluded units is shown below:

Exhibit 4-6. PREPA Existing Units Excluded from the IRP

	Generation Units	Capacity (MW)
Steam Turbine (MATS Affected)	Costa Sur 3 ST	85
	Costa Sur 4 ST	85
	Palo Seco 1 ST	85
	Palo Seco 2 ST	85
	San Juan 9 ST	100
	San Juan 10 ST	100
Gas Turbine	Cambalache 1 GT	83
Total		**623**

Source: PREPA, Siemens.

Note: San Juan 9 may be substitured for San Juan 7 or 8 without material impacts to model results.

4.2.1.1 Steam Turbines (ST)

PREPA has a total of 14 ST units with a total capacity of 2,892 MW located at four sites, Palo Seco (4 units, 602 MW) and San Juan (4 units, 400 MW) in the north; Aguirre (2 units, 900 MW) and Costa Sur (4 units, 990 MW) in the south. All the ST units are subject to MATS compliance requirements. A total of 6 of the 14 ST units, 2 each at Palo Seco, San Juan and Costa Sur, as listed in Exhibit 4-2, were excluded from resources for this IRP due to their age and current non-operational condition.

The remaining eight MATS-affected units, with a total capacity of 2,352 MW, were operational and included in this IRP. These ST units are located at four sites including Palo Seco (2 units, 432 MW), and San Juan (2 units, 200 MW) in the north; and Aguirre (2 units, 900 MW), and Costa Sur (2 units, 820 MW) in the south. The Costa Sur ST units 5&6 are MATS compliant and have dual fuel capability, which can also burn No. 6 fuel oil but currently burn 100 percent natural gas. Exhibit 4-3 shows the unit level parameters of the eight ST units included in the IRP.

Exhibit 4-7. ST Unit Parameters (Aguirre, Costa Sur, Palo Seco, San Juan)

Parameters	Unit	Aguirre ST		Costa Sur ST	
		Unit 1	Unit 2	Unit 5	Unit 6
Fuel	Type	No. 6 fuel oil	No. 6 fuel oil	Natural Gas	Natural Gas
Maximum Capacity	MW	450	450	410	410
Minimum Capacity	MW	200	200	180	180
Fixed O&M Expense	2018 $/kW-year	32.04	32.04	35.96	35.96
Variable O&M Expense	2018 $/MWh	2.25	2.25	2.72	2.72
Heat Rate at Maximum Capacity	MMBtu/MWh	9.60	9.70	9.75	9.75
Heat Rate at Minimum Capacity	MMBtu/MWh	9.94	10.16	9.93	10.07
Forced Outage	%	20	20	2	4
Minimum Downtime	Hours	48	48	48	48
Minimum Runtime	Hours	720	720	720	720
Ramp Up Rate	MW/minute	5	5	5	5
Ramp Down Rate	MW/minute	5	5	5	5

Parameters	Unit	Palo Seco ST		San Juan ST	
		Unit 3	Unit 4	Unit 7	Unit 8
Fuel	Type	No. 6 fuel oil	No. 6 fuel oil	No. 6 fuel oil	No. 6 fuel oil
Maximum Capacity	MW	216	216	100	100
Minimum Capacity	MW	130	130	70	70
Fixed O&M Expense	2018 $/kW-year	46.47	46.47	49.02	49.02
Variable O&M Expense	2018 $/MWh	4.95	4.95	2.93	2.93
Heat Rate at Maximum Capacity	MMBtu/MWh	9.73	9.73	10.50	10.45
Heat Rate at Minimum Capacity	MMBtu/MWh	10.35	10.35	10.50	10.50
Forced Outage	%	42	42	15	15
Minimum Downtime	Hours	48	48	48	48
Minimum Runtime	Hours	720	720	720	720
Ramp Up Rate	MW/minute	3	3	3	3
Ramp Down Rate	MW/minute	3	3	3	3

Note: Aguirre ST and Costa Sur ST units have an emergency minimum capacity of 150 MW and 100 MW respectively.
Source: PREPA, Siemens.

The minimum capacity levels correspond to the minimum output that would still allow the units to return to a regulating operating mode within the hour, according to PREPA operations. There are lower capacity levels (e.g. Costa Sur ST 5&6 at 100 MW and Aguirre ST 1&2 at 150 MW), but these lower capacities would require multiple hours for the units to return to regulating operating mode.

The minimum run time reported was defined by PREPA’s operations team to prevent the units from weekly cycling as was observed in prior studies that included high levels of renewable penetration.

The reported heat rates correspond to the values currently used in PREPA’s models, adjusted if necessary for the reduced operating limits. These heat rates are reasonable for the technologies considered and are the best information available at this time.

For the forced outage assumption, Siemens reviewed the reported forced outage statistics for each unit from 2011 to October 2016 (reported Forced Outage Factor), in addition to the forced outage rate (FOR) currently used in PREPA’s models and the recent experience with the units.

Siemens increased the outage rate of Aguirre ST 1&2 from 4 percent in PREPA's existing models to 20 percent based on both the increase in forced outages experienced during 2010-2016 and the overall unit's condition. Costa Sur ST 5 was left unchanged at 2 percent and Costa Sur ST 6 was increased slightly from 3 percent to 4 percent. Costa Sur units 5&6 are expected to be thoroughly inspected and repaired.

Palo Seco ST units 3and 4 have had fairly poor performance and Siemens increased the FOR to 42% to be conservative and in line with the 45% availability observed. Finally, San Juan ST 7&8 outage rates were modeled at 15% to reflect 70% observed availability.

Based on discussions with PREPA staff, Siemens excluded Costa Sur ST 3&4, Palo Seco ST 1&2 and San Juan ST 9&10 with a total of 540 MW from the IRP study, because these units are not in acceptable operating condition, are not in MATS compliance, and would require large investments that do not appear to be economic, to achieve MATS compliance and working condition.

4.2.1.2 Combined Cycles Gas Turbine (CCGT)

PREPA's four Combined Cycle Gas Turbine (CCGT) units run on diesel. These units include Aguirre 1&2 CC (260 MW each) and San Juan 5&6 CC (200 MW each) with a total capacity of 920 MW. The Aguirre CCGT units went into commercial operation in 1975-1976 and are inefficient with very low historical dispatch levels. The nominal capacity of these units is 296 MW each, but this has been limited to 260 MW in this study[17]. These units can be economically retired in the IRP, however before the entry of a new CCGT in the south they do provide support in the case of MiniGrid isolated operations, when the load in the system could be too small for larger units like AES Coal or EcoEléctrica (in combine cycle mode) to be dispatched.

San Juan 5&6 CCGT units (also known as the San Juan Repower) began commercial operation in 2008 have a heat rate of 7,625 Btu/kWh and 7,853 Btu/kWh, respectively. These units serve as an important generation resource operating in the north of the island. Their nominal capacity is 220 MW per unit, but this is limited to 200 MW in this study.

Exhibit 4-4 shows the unit level parameters of the four CCGT units included in the IRP. The heat rates correspond to the modeled values and it is important to note that these units should preferably be able to cycle daily if necessary to integrate renewable generation. However, as shown below PREPA has determined that the current minimum run time is 120 hours (5 days) which would allow these units to cycle weekly and be off only during the weekends.

The historical outage factors (2010 to 2016) for the Aguirre CC show values on the order of 2 percent for the Aguirre CC Unit 1 and 10 percent for Aguirre CC Unit 2, possibly due to its relatively low dispatch. However, the outage factor for these units was left at 20 percent considering their recent performance, as Siemens noted that Aguirre CCGT unit 2 had fairly poor performance with 33 percent steam turbine outage in 2015 and 20 percent outage in 2016. For San Juan CC, history has shown relatively poor availability in both units but better than the prior modeled 20 percent for San Juan unit 5 and worse for San Juan unit 6 (10 percent used in prior modeling). Thus, both units are modeled in this IRP at 18 percent forced outage rate, in line with the historical values.

[17] The maximum capacities considered in the study are based on information provided by PREPA.

Exhibit 4-8. CC Units Parameters (Aguirre and San Juan)

Parameters	Unit	Aguirre CC		San Juan CC	
		Unit 1	Unit 2	Unit 5	Unit 6
Fuel	Type	Diesel	Diesel	Diesel	Diesel
Maximum Capacity	MW	260	260	200	200
Minimum Capacity	MW	46	46	155	155
Fixed O&M Expense	2018 $/kW-year	22.64	22.64	27.40	27.40
Variable O&M Expense	2018 $/MWh	6.79	6.79	2.22	2.22
Heat Rate at Maximum Capacity	MMBtu/MWh	11.14	11.14	7.63	7.85
Heat Rate at Minimum Capacity	MMBtu/MWh	11.42	11.42	8.46	8.86
Forced Outage	%	20	20	18	18
Minimum Downtime	Hours	0	0	48	48
Minimum Runtime	Hours	2	2	120	120
Ramp Up Rate	MW/minute	5	5	3	3
Ramp Down Rate	MW/minute	5	5	3	3

Source: PREPA, Siemens.

4.2.1.3 Gas Turbines

Out of the 25 GT units, 24 units, with a total capacity of 743 MW, are included in the IRP. The GTs include Cambalache GT 2&3 (82.5 MW each), Mayagüez GT 1 through 4 (50 MW each), and nine pairs of distributed GTs (21 MW each) spread across the island. The Mayagüez units are four aero-derivative gas turbines with relatively good efficiency. The distributed GT's (21 MW each) include pairs of two units located: Daguao (2x21), Palo Seco (6x21), Aguirre (2x21), Costa Sur (2x21), Jobos (2x21), Yabucoa (2x21), and Vega Baja (2x21). These nine pair of distributed units, while in operating condition, are fairly old and have very poor heat rates. Fourteen of these units are retired early in the IRP capacity expansion plan and replaced by new peakers.

Based on discussions with PREPA staff, Cambalache GT 1 will be excluded from the IRP because it is not planned to be returned to operating condition in the foreseeable future. The two 21 MW GTs at Aguirre and two 21 MW GTs at Costa Sur are necessary to provide black-start capability to their respective combined cycle and steam turbine at each location. These gas turbines can only be retired after new units are installed with black-start capability.

Exhibit 4-5 shows the unit level parameters of the 24 GT units considered in the IRP. The heat rates and forced outages are as modeled in the PREPA's models. The distributed GTs and the Mayagüez units can cycle with zero downtime and runtime.

Exhibit 4-9. GT Units Parameters (Cambalache, Mayagüez and Nine Pairs of Distributed GT units)

Parameters	Unit	Cambalache CT		GT Units
		Unit 2	Unit 3	Each Unit
Fuel	Type	Diesel	Diesel	Diesel
Maximum Capacity	MW	83	83	21
Minimum Capacity	MW	50	50	21
Fixed O&M Expense	2018 $/kW-year	24.44	24.44	26.54
Variable O&M Expense	2018 $/MWh	5.52	5.52	20.19
Heat Rate at Maximum Capacity	MMBtu/MWh	11.55	11.55	14.40
Heat Rate at Minimum Capacity	MMBtu/MWh	11.55	11.55	14.40
Forced Outage	%	10.0	10.0	15
Minimum Downtime	Hours	7	7	0
Minimum Runtime	Hours	7	7	0
Ramp Up Rate	MW/minute	2	2	2
Ramp Down Rate	MW/minute	2	2	2

Parameters	Unit	Mayagüez CT			
		Unit 1	Unit 2	Unit 3	Unit 4
Fuel	Type	Diesel	Diesel	Diesel	Diesel
Maximum Capacity	MW	50	50	50	50
Minimum Capacity	MW	25	25	25	25
Fixed O&M Expense	2018 $/kW-year	10.64	10.64	10.64	10.64
Variable O&M Expense	2018 $/MWh	6.40	6.40	6.40	6.40
Heat Rate at Maximum Capacity	MMBtu/MWh	9.32	9.32	9.32	9.32
Heat Rate at Minimum Capacity	MMBtu/MWh	11.20	11.20	11.20	11.20
Forced Outage	%	9	9	9	9
Minimum Downtime	Hours	0	0	0	0
Minimum Runtime	Hours	0	0	0	0
Ramp Up Rate	MW/minute	6	6	6	6
Ramp Down Rate	MW/minute	6	6	6	6

Source: PREPA, Siemens.

4.2.1.4 Hydro

PREPA has 21 hydroelectric generating units at 11 generating facilities for a total installed nameplate capacity of 105 MW. However, some of these units are not operational, or are underutilized due to staffing and funding shortages resulting in deferred maintenance issues. The operational units total 34 MW with a capacity factor of less than 20 percent as of the first quarter of 2018. In an effort to alternative methods that could economically increase the output and continuing operation from these clean hydroelectric resources, PREPA issued a Request for Proposal (RFP) regarding long-term lease and energy sales agreement for their hydroelectric power plants[18]. Exhibit 4-6 shows a Scenario to increase hydroelectric contribution to 70 MW, assuming a high-level estimate of a total of $100 million investment through 2023. This value of 70 MW should be considered a possible outcome of a refurbishing project, like the one considered, but larger values are possible.

[18] REQUEST FOR PROPOSALS: Long-Term Lease and Energy Sales Agreement(s) for Hydroelectric Power Plants Owned by: Puerto Rico Electric Power Authority

Exhibit 4-10. PREPA Operational Hydro Capacity Assumptions

Year	2019	2020	2021	2022	2023
Capacity (MW)	34	50	70	70	70
Availability Factor	20%	40%	60%	80%	90%
Capacity Factor	15%	25%	28%	28%	28%
Annual Generation GWh	44,676	109,500	171,696	171,696	171,696

Source: PREPA, Siemens.

4.2.1.5 EcoEléctrica PPOAs

To supplement its own capacity, PREPA purchases power from two co-generators under the terms and conditions of PPOAs, including 507 MW natural gas-fired combined cycle plant from EcoEléctrica, L.P. and 454 MW coal-fired steam electric cogeneration station from AES. The 961 MW of capacity provided by the two co-generators brings the total capacity available to PREPA to 5,011 MW[19].

In accordance with a 22-year PPOA that commenced in March 2000, each calendar year EcoEléctrica fixes the fuel cost per million BTU for the first 76 percent of the station's capacity for that year. For capacity in excess of 76 percent, PREPA has been charged a price based upon a spot[20] fuel price set by EcoEléctrica at the time the excess capacity was dispatched.

The EcoEléctrica contract has a target availability factor of 93 percent, with associated capacity payments.

The operational and cost parameters of the EcoEléctrica is shown below.

[19] This value corresponds to the sum of the maximum capacities considered in this study and includes the GTs and 34 MW of hydro units.
[20] This "spot price" is not directly related to the spot price of fuels in the market.

Exhibit 4-11. EcoEléctrica Operational Parameters
(Fiscal Year used and EcoEléctrica prior negotiation)

Parameters	Unit	EcoEléctrica CC Unit 1
Fuel	Type	Natural Gas
Maximum Capacity	MW	507
Minimum Capacity	MW	275
Fixed O&M Expense	2018 $/kW-year	162.05
Variable O&M Expense	2018 $/MWh	0.00
Capital Costs	2018 $(000)	124,226
Heat Rate at Maximum Capacity	MMBtu/MWh	7.50
Heat Rate at Minimum Capacity	MMBtu/MWh	8.31
Forced Outage	%	2
Minimum Downtime	Hours	8
Minimum Runtime	Hours	168
Ramp Up Rate	MW/minute	10
Ramp Down Rate	MW/minute	10

Year	EcoEléctrica CC				
	Fixed O&M Costs (Nominal $/kW)	Variable O&M Costs (Nominal $/MWh)	Capital Costs (Nominal $000)	Capacity Payment (Nominal $000)	Monthly Avg (Nominal $000)
2018	162.05	0.00	124,226	206,062	17,172
2019	166.40	0.00	109,621	193,651	16,138
2020	170.84	0.00	120,962	207,238	17,270
2021	194.28	0.00	140,989	239,103	19,925
2022	198.95	0.00	143,808	244,277	20,356
2023	203.72	0.00	146,685	249,564	20,797
2024	208.61	0.00	149,618	254,967	21,247
2025	213.62	0.00	152,611	260,488	21,707
2026	218.75	0.00	155,663	266,129	22,177
2027	224.00	0.00	158,776	271,894	22,658
2028	229.37	0.00	161,952	277,784	23,149
2029	234.88	0.00	165,191	283,803	23,650
2030	240.51	0.00	168,495	289,954	24,163
2031	246.29	0.00	171,864	296,238	24,687
2032	252.20	0.00	175,302	302,661	25,222
2033	258.25	0.00	178,808	309,223	25,769
2034	264.45	0.00	182,384	315,930	26,327
2035	270.79	0.00	186,032	322,782	26,899
2036	277.29	0.00	189,752	329,785	27,482
2037	283.95	0.00	193,547	336,941	28,078
2038	283.95	0.00	193,547	336,941	28,078

Source: PREPA, Siemens. See Workpaper: Existing Units Parameters _1229 2018_V6.1.xlsx

Based on discussions with PREPA, a renewal of EcoEléctrica PPOA is assumed in the base Scenarios of the IRP; however, the plant is subject to economic retirement, if it is decided by the least cost plan. The retirement of EcoEléctrica introduces development risks associated with new replacement resources which make the renegotiation of the PPOA an important consideration for PREPA.

A reduction on the fixed payments is assumed after 2022 and the required reduction on the capacity payments for EcoEléctrica to be competitive is a function of the generation that would otherwise replace it, including the possible combined cycle gas turbine (CCGT) at Costa Sur and the balance of the generation that would make up the future generation fleet and in particular the solar PV and associated storage.

Siemens estimated that the fixed payment should be reduced by 53% from 2022 onwards (e.g. new Year 2022 total payment $115.3 million down from $245.3[21] projected without the reduction, see Exhibit below).

The fixed payment reduction was determined based on the initial results of the ESM and identifying the reduction in fixed payments necessary to make the NPV of EcoEléctrica's "All in" costs the same as that of an equivalent reference CCGT that could produce the same capacity and energy. This analysis is documented in the workpaper: EcoElectrica_NPV_ASSESSMENT_Initial.xlsx. The exhibit below shows the results of the analysis and the actual fixed payments modeled by calendar year (Aurora is a calendar year model).

Exhibit 4-12. EcoEléctrica Original and Modeled Capacity Payments.

	Original			Modeled based on Eq CCGT NPV analysis.			
Calendar Year	Fixed O&M Costs (Nominal 000$)	Capital Costs (Nominal $000)	Total Fixed Costs (Nominal $000)	Fixed O&M Costs (Nominal 000$)	Capital Costs (Nominal $000)	Total Fixed Costs (Nominal $000)	Reduction
2019	84,594	109,923	194,517	84,594	109,923	194,517	0%
2020	87,092	121,628	208,720	87,092	121,628	208,720	0%
2021	98,772	141,377	240,149	98,772	141,377	240,149	0%
2022	101,143	144,184	245,327	47,537	67,767	115,304	53%
2023	103,570	147,092	250,662	48,678	69,133	117,811	53%
2024	106,348	150,464	256,813	49,984	70,718	120,702	53%
2025	108,601	153,014	261,615	51,042	71,917	122,959	53%
2026	111,207	156,081	267,288	52,268	73,358	125,625	53%
2027	113,878	159,200	273,078	53,522	74,824	128,347	53%
2028	116,931	162,817	279,748	54,957	76,524	131,482	53%
2029	119,408	165,651	285,059	56,122	77,856	133,978	53%
2030	122,274	168,982	291,255	57,469	79,421	136,890	53%
2031	125,211	172,313	297,523	58,849	80,987	139,836	53%
2032	128,565	176,284	304,849	60,426	82,853	143,279	53%
2033	131,291	179,292	310,583	61,707	84,267	145,974	53%
2034	134,442	182,887	317,330	63,188	85,957	149,145	53%
2035	137,670	186,535	324,206	64,705	87,672	152,377	53%
2036	141,358	190,811	332,169	66,438	89,681	156,120	53%
2037	144,356	194,096	338,452	67,847	91,225	159,073	53%
2038	144,356	194,096	338,452	67,847	91,225	159,073	53%
						Average	53%

Source: EcoElectrica_NPV_ASSESSMENT_Initial.xlsx.

[21] Fixed Payment is the sum of the Fixed O&M and Capacity Payment and for year 2022.

This reduction above was close but not enough to prevent EcoEléctrica from being retired, and once the LTCE were completed we found that under the scenarios that allowed EcoEléctrica to be replaced by the CCGT, it would happen. The underlying reason for this is the fact that under the new runs the projected capacity factors of EcoEléctrica are lower than in the initial runs of the IRP. To address this situation the required reduction would be 60%, instead of the modeled 53%. This was confirmed with a second assessment using the new capacity factors see workpaper EcoElectrica_NPV_ASSESSMENT_Update.xlsx. Given that the future capacity factors are highly uncertain, no reruns of the LTCE were made, but the possibility of EcoEléctrica staying online was treated via a sensitivity to Scenario 4, for its comparison with the ESM that maintained this plant.

For EcoEléctrica the gas prices 2022 onwards are assumed to reflect the cost of the commodity, the cost of liquefaction and the cost of transportation only and assume that the long-term contract that EcoEléctrica had for reduced natural gas prices expires. Other regasification costs are modeled as part of the fixed payment above (see section 7.2.5 Forecast Delivered Fuel Prices).

Finally, EcoEléctrica as has been traditionally modeled as a Base Load plant and it was allowed only to cycle on a weekly basis. However, this limitation in a system with high penetration of renewable generation, as in the future Puerto Rico system, would create important renewable generation curtailment and/or increase the need for investments in storage. Hence the assumption was made that for EcoEléctrica to remain competitive and viable in this future system it would have to be modified so it could be turned off during daytime (e.g. after 6:00 to 7:00 am) and turned back on in the evening (after 4:00 to 5:00 pm) to supply the night load. Note that to achieve this EcoEléctrica would need to keep its HRSG a warm / hot conditions and possibly improve its controls and equipment to manage the thermal stresses. EcoEléctrica was modeled with a minimum down time of 2 hours and a minimum up time of 2 hours, instead of the initially modeled 5 days minimum up time.

4.2.1.6 AES PPOAs

AES's coal-fired steam electric cogeneration station began commercial operation in November 2002. The owners of the facility have entered into a PPOA with the PREPA to provide 454 MW of power for a period of 25 years. IRP will not assume a renewal of the AES PPOA, in line with the provision of Act 17-2019 that precludes the use of Coal Fired generation after January 1st 2028.

The operational and cost parameters of the AES is are shown below.

Exhibit 4-13. AES Operational Parameters (Fiscal Year used)

Parameters	Unit	AES Coal Plant Unit 1	AES Coal Plant Unit 2
Fuel	Type	Coal	Coal
Maximum Capacity	MW	227	227
Minimum Capacity	MW	166	166
Fixed O&M Expense	2018 $/kW-year	77.96	77.96
Variable O&M Expense	2018 $/MWh	7.09	7.09
Capital Costs	2018 $(000)	121,499	121,499
Heat Rate at Maximum Capacity	MMBtu/MWh	9.79	9.79
Heat Rate at Minimum Capacity	MMBtu/MWh	9.93	9.93
Forced Outage	%	3	3
Minimum Downtime	Hours	48	48
Minimum Runtime	Hours	720	720
Ramp Up Rate	MW/minute	0	0
Ramp Down Rate	MW/minute	0	0

Year	AES Coal Plant Fixed O&M Costs (Nominal $/kW)	AES Coal Plant Variable O&M Costs (Nominal $/MWh)	AES Coal Plant Capital Costs (Nominal $000)
2018	77.96	7.09	121,499
2019	79.83	7.26	122,916
2020	81.75	7.43	122,991
2021	83.71	7.61	108,311
2022	85.72	7.79	94,026
2023	87.78	7.98	83,779
2024	89.88	8.17	74,127
2025	92.04	8.37	74,865
2026	94.25	8.57	75,627
2027	96.51	8.78	76,390
2028	98.83	8.99	77,159
2029	101.20	9.20	77,934
2030	103.63	9.42	78,714
2031	106.11	9.65	79,502
2032	108.66	9.88	80,298
2033	111.27	10.12	81,103
2034	113.94	10.36	81,915
2035	116.67	10.61	82,735
2036	119.47	10.86	83,564
2037	122.34	11.12	84,400
2038	122.34	11.12	84,400

Source: PREPA, Siemens. See Workpaper: Existing Units Parameters _1229 2018_V6.1.xlsx

4.2.2 Utility Scale Renewable PPOAs

This section includes a summary of the projects that were considered for modeling of the renewable generators. Between 2008 and 2012, PREPA signed 68 renewable PPOAs. As of December 2018, 58 PPOAs remained in effect with a total capacity of 1,480.6 MW, out of which 11 contracts are in operation.

4.2.2.1 PPOAs in Commercial Operation or in Pre-Operation

As of December 2018, 11 PPOAs are in either commercial operation or in pre-operation (energized, under testing, and selling energy and renewable energy credits to PREPA). These projects represent 272.9 MW of capacity, including 147.1 MW of solar photovoltaic (PV), 121 MW of wind, and 4.8 MW of landfill gas.

Exhibit 4-8 shows the eight PPOAs in commercial operation as of December 2018, with a total capacity of 200.5 MW. Even though the installed capacity of Pattern Santa Isabel is 95 MW, the maximum capacity has been limited to 75 MW due to contractual limitation of compliance with the Minimum Technical Requirements (MTR).). The plant capacity could increase to 95 MW during certain months (February to September), but it has not been allowed to reach these levels as the plant currently does not meet the MTR at those levels. The plant was modeled in this IRP at 75 MW, which will continue until Pattern can show that it meets the Minimum Technical Requirements with the increased output.

Exhibit 4-14. Eight PPOAs under Commercial Operation

Ref. Number	Name	Status	Contract Number	Technology	Capacity MW
1	AES Ilumina	Operation	2010-P00050	Solar	20
18	Horizon Energy	Operation	2011-P00034	Solar	10
46	San Fermin Solar (Coqui Power)	Operation	2011-P00050	Solar	20
60	Windmar (Cantera Martino)	Operation	2010-P00052	Solar	2.1
30	Yarotek (Oriana)	Operation	2011-P00048	Solar	45
32	Go Green (Punta Lima)	Operation	2010-AI0001	Wind	26
31	Pattern (Pattern Santa Isabel)	Operation	2010-P00047	Wind	75
24	Fajardo Landfill Tech (Landfill Gas Technologies of Fajardo)	Operation	2013-P00046	Landfill G	2.4
		Total Capacity			**200.5**

Source: PREPA, Siemens.

The capacity factors for these PPOAs were derived from an assessment of the historical performance of them as shown in Exhibit 4-9. The Model Target is the forecasted capacity factor. Plant specific capacity factor estimates were derived considering the history and the fact that some years were partial operation or pre-operation.

Exhibit 4-15. Historical Capacity Factors for Eight PPOAs in Commercial Operation

Ref Number	Name		2016 Hourly	2015 5-minute	2016 5-minute	2017 5-minute	Model Target
1	AES Illumina		22%	23%	22%	24%	**23%**
18	Horizon		27%	19%	27%	29%	**24%**
24	Fajardo Landfill Tech (Landfill Gas Technologies of Fajardo)		52%				**80%**
30	Yarotek (Oriana)				9%	25%	**25%**
46	San Fermin (Coqui Power)		22%				**22%**
60	Windmar (Cantera Martino)		23%	25%	23%	26%	**24%**
		2013 Hourly	**2014 Hourly**	**2015 Hourly**	**2016 Hourly**	**2017 Hourly**	
31	Pattern (Pattern Santa Isabel)	18%	25%	27%	22%	25%	**23%**
32	Go Green (Punta Lima)	25%	24%	26%	22%	24%	**24%**

Exhibit 4-10 shows the PPOAs in pre-operation as of December 2018, with a total capacity of 52.4 MW. Humacao Solar Project, LLC is being developed in two phases: Phase 1 (20 MW) is in testing

and Phase 2 (20 MW) is under construction as of December 20182018. A landfill gas project, Landfill Gas Technologies of Fajardo, LLC (Toa Baja Landfill), completed testing in July of 2017 and was in the process of achieving commercial operation when hurricanes Irma and María struck in September 2017. It is expected that the facility will be declared in commercial operation in 2019, so the plant is considered under commercial operation in the IRP. Exhibit 4-10 lists the PPOAs under pre-operation as of December 2018.

For the existing solar PPOAs and all future solar projects, the IRP has assumed a capacity factor of 22%. This value is viewed as conservative since the historical values are slightly higher, in the 23% range. For landfill gas, a capacity factor of 80% is assumed in this IRP.

Exhibit 4-16. Three PPOAs under Pre-Operation

Ref. Number	Name	Status	Contract Number	Technology	Capacity MW
7	Fonroche Energy (Humacao Solar Project)	Pre-Operation	2012-P00031	Solar	40.0
62	Windmar (Vista Alegre/Coto Laurel)	Pre-Operation	2012-P00052	Solar	10.0
25	Toa Baja Landfill Tech (Landfill Gas Technologies of Fajar	Pre-Operation	2013-P00073	Landfill G	2.4
		Total Capacity			**52.4**

Source: PREPA, Siemens.

4.2.2.2 PPOAs in Renegotiation

Of the 18 PPOAs successfully renegotiated and amended in 2013-2014, 15 have not begun construction. Between 2015 and 2016, most of these companies requested extensions to start construction and commercial operation dates established in their PPOAs. Most of the requests were related to the difficulties alleged by the companies in securing financing for their projects due to the financial situation of the Government of Puerto Rico and PREPA. Exhibit 4-11 shows the list of the PPOAs under renegotiation. The PPOAs under re-negotiation are modeled as potential new supply options (volumes and sites), assuming benchmarked new solar prices instead of the PPOAs actual prices.

Exhibit 4-17. Fifteen PPOAs under Renegotiation

Ref. Number	Name	Status	Contract Number	Technology	Capacity MW
5	Atenas Solar Farm (Desarrollos del Norte)	Re-negotiation	2013-P00070	Solar	20
3	Blue Beetle III	Re-negotiation	2012-P00037	Solar	20
4	Ciro Group (Ciro One Salinas)	Re-negotiation	2011-P00043	Solar	57
15	Grupotec USA Inc (Xzerta-Tec)	Re-negotiation	2013-P00042	Solar	20
16	Guayama Solar Farm (Guayama Solar Energy)	Re-negotiation	2011-P00042	Solar	17.8
21	Irradia Energy USA (Morovis Solar Farm)	Re-negotiation	2012-P00053	Solar	33.5
42	Moca Solar Farm	Re-negotiation	2013-P00003	Solar	20
43	North Coast Solar	Re-negotiation	2013-P00041	Solar	20
36	Renewable Energy Authority (Vega Serena)	Re-negotiation	2012-P00045	Solar	20
39	Resun (Barceloneta)	Re-negotiation	2012-P00061	Solar	20
47	Solaner	Re-negotiation	2012-P00146	Solar	25
48	Solar Blue (Solar Blue Bemoga)	Re-negotiation	2013-P00052	Solar	20
57	WindMar (Santa Rosa)	Re-negotiation	2012-P00080	Solar	20
63	YFN Yabucoa Solar (Justin Orozco)	Re-negotiation	2013-P00049	Solar	20
6	Energy Answers Arecibo	Re-negotiation	2010-AI0018	WTE	79
		Total Capacity			**412.3**

Source: PREPA, Siemens.

With respect of the Energy Answers Arecibo PPOA project, there are a number of permitting and local opposition challenges. Among others, the Governor of Puerto Rico retired the administration endorsement to the project. Hence, this project will not be considered as part of the IRP, which is conservative, as its location on the north of the transmission system and high contribution to the RPS would result in a favorable outcome from these two points of view. Other waste to energy technologies could be considered instead.

4.2.2.3 PPOAs not Re-negotiated

There are 32 projects with PPOAs subject to renegotiation. For the IRP, these projects provide an indication of available sites that may be utilized by alternative renewable generation projects. Exhibit 4-12 lists the 32 PPOAs which were not renegotiated. These projects were considered in the IRP as potential new supply options (capacity and sites), assuming benchmarked new prices instead of the PPOAs actual prices.

Exhibit 4-18.Thirty two PPOAs not Re-negotiated

Ref. Number	Name	Status	Contract Number	Technology	Capacity MW
41	Cabo Solar	Not Renegotiated	2013-P00069	Solar	20
44	Caracol Solar (Roma Solar) LLC	Not Renegotiated	2013-P00004	Solar	20
52	Carolina Solar (Trina)	Not Renegotiated	2013-P00067	Solar	20
10	Fonroche Energy (Humacao Solar Project)	Not Renegotiated	2013-P00048	Solar	15
9	Fonroche Energy (Solar Project Ponce)	Not Renegotiated	2013-P00045	Solar	30
12	Fonroche Energy (Vega Baja Solar Project)	Not Renegotiated	2013-P00050	Solar	15
8	Fonroche Energy (Lajas Solar Project)	Not Renegotiated	2013-P00046	Solar	10
11	Fonroche Energy (South Solar 2)	Not Renegotiated	2013-P00047	Solar	30
13	GG Alternative Energy Corp.	Not Renegotiated	2013-P00077	Solar	20
17	Hatillo Solar (Pattern)	Not Renegotiated	2013-P00074	Solar	30
19	HSEA PR Isla Solar I	Not Renegotiated	2013-P00057	Solar	40
22	Jonas Solar Farm (Jonas Solar Energy)	Not Renegotiated	2012-P000140	Solar	40
23	Juncos Solar Energy	Not Renegotiated	2012-P00138	Solar	20
26	M Solar (M Solar Generating)	Not Renegotiated	2012-P00142	Solar	50
34	REA Ceiba (REA Energy Ceiba Solar Plant)	Not Renegotiated	2013-P00076	Solar	20
33	REA Energy (Luquillo Solar Plant)	Not Renegotiated	2013-P00051	Solar	20
35	REA Hatillo (REA Energy Hatillo Solar Plant)	Not Renegotiated	2013-P00075	Solar	20
45	Sierra Solar (Roma Solar)	Not Renegotiated	2013-P00072	Solar	20
53	Vega Baja Solar Energy	Not Renegotiated	2012-P00139	Solar	30
54	Western Wind (Yabucoa Solar)	Not Renegotiated	2011-P00090	Solar	30
56	WindMar (Dorado-Toa Baja)	Not Renegotiated	2012-P00079	Solar	20
2	Aspenall Energy	Not Renegotiated	2012-P00089	Wind	10
14	GG Alternative Energy Corp.	Not Renegotiated	2013-P00071	Wind	10
50	Tradewind Energy (Tradewinds Energy Barceloneta)	Not Renegotiated	2012-P00030	Wind	75
51	Tradewind Energy (Tradewinds Energy Vega Baja)	Not Renegotiated	2012-P00028	Wind	50
55	Wind to Energy	Not Renegotiated	2011-P00101	Wind	20
58	WindMar (Dorado-Toa Baja)	Not Renegotiated	2012-P00095	Wind	44
61	Windmar (Punta Ventana)	Not Renegotiated	2008-AI0066C	Wind	18.4
59	Windmar (Punta Verraco)	Not Renegotiated	2012-P00049	Wind	34.5
49	Sunbeam	Not Renegotiated	2010-AI0031	WTE	10
37	Renewable Power Group	Not Renegotiated	2012-P00010	Landfill G	2
38	Renewable Power Group	Not Renegotiated	2012-P0009	Landfill G	1.5
		Total Capacity			**795.4**

Source: PREPA, Siemens.

4.2.2.4 PPOAs Assumed Contract Pricing

As indicated earlier, any project that is not in operation or pre-operation (i.e. all other projects irrespective of having re-negotiated PPOAs or not), was modeled in the IRP as potential new supply sites with commercial conditions according to Siemens forecast for new solar prices. Actual pricing for re-negotiated PPOAs may deviate from this assumption to reflect legacy development and carrying costs attributable to delays in financing and construction.

For the projects in operation or pre-operation, Siemens assumed the price conditions shown in Exhibit 4-13, where the Contract Price is inclusive of RECs and does not have escalation clauses.

Exhibit 4-19. Projects in Operation or Pre-operation Prices

Project Type	Contract Price $/MWh
Solar PV	150
Wind	125
Land fill gas	100

Note: above prices include RECs and does not have escalation clauses.

4.3 Environmental Considerations

Environmental regulations have the potential to impact the overall cost and operation of electric generation. As such, compliance requirements for key environmental regulations with the potential to significantly impact portfolio costs and resource decisions need to be factored into this IRP analysis. This initial review considered existing regulations and the outlook for potential new compliance requirements over the study horizon (2019-2038). An overview of these key regulations, applicability to PREPA's existing and future portfolio and the approach to incorporate compliance into the IRP analysis are documented in this section. Although there are numerous environmental policies impacting the energy sector at the federal, state and local levels, the primary policies that are driving power markets and generation decisions are the suite of Environmental Protection Agency (EPA) rules addressing power plant emissions and state driven renewable and alternative energy portfolio standards. The environmental regulations determined by Siemens and PREPA to be potentially significant and factored into the IRP analysis include federal air regulations, water regulations, and local policy dictating targets for renewable and alternative energy, specifically:

- National Ambient Air Quality Standards (NAAQS)
- Mercury and Air Toxics Standards (MATS)
- Carbon Regulation
  - Greenhouse Gas (GHG) Emission Standards for New, Modified, and Existing Electric Generating Units
  - Outlook for potential future regulation of GHG emissions from power generators
- Puerto Rico Renewable Porfolio Standard (RPS)
- Section 316(b) of the Clean Water Act

- Puerto Rico Water Quality Standards Regulation

A summary of PREPA's generating units and applicability to the air quality regulations is presented in Exhibit 4-14.

Exhibit 4-20: Summary of PREPA Units[22] and Emissions Regulatory Coverage

	Generation Units	Capacity (MW)	Fuel	SO2 EPA Final Designation	MATS Affected	Carbon Emissions
MATS Affected Units	Aguirre 1 ST	450	No. 6 fuel oil	Nonattainment	Yes	Yes
	Aguirre 2 ST	450	No. 6 fuel oil	Nonattainment	Yes	Yes
	Costa Sur 3 ST*	85	No. 6 fuel oil	Attainment/Unclassifiable	Yes	Yes
	Costa Sur 4 ST*	85	No. 6 fuel oil	Attainment/Unclassifiable	Yes	Yes
	Costa Sur 5 ST	410	Natural gas, No. 6 fuel oil capable	Attainment/Unclassifiable	Yes	Yes
	Costa Sur 6 ST	410	Natural gas, No. 6 fuel oil capable	Attainment/Unclassifiable	Yes	Yes
	Palo Seco 1 ST*	85	No. 6 fuel oil	Nonattainment	Yes	Yes
	Palo Seco 2 ST*	85	No. 6 fuel oil	Nonattainment	Yes	Yes
	Palo Seco 3 ST	216	No. 6 fuel oil	Nonattainment	Yes	Yes
	Palo Seco 4 ST	216	No. 6 fuel oil	Nonattainment	Yes	Yes
	San Juan 7 ST	100	No. 6 fuel oil	Nonattainment	Yes	Yes
	San Juan 8 ST	100	No. 6 fuel oil	Nonattainment	Yes	Yes
	San Juan 9 ST*	100	No. 6 fuel oil	Nonattainment	Yes	Yes
	San Juan10 ST*	100	No. 6 fuel oil	Nonattainment	Yes	Yes
Combined Cycle	Aguirre 1 CC	260	Diesel	Nonattainment	No	Yes
	Aguirre 2 CC	260	Diesel	Nonattainment	No	Yes
	San Juan 5 CC	200	Diesel	Nonattainment	No	Yes
	San Juan 6 CC	200	Diesel	Nonattainment	No	Yes
Gas Turbine	Cambalache 2 GT	83	Diesel	Attainment/Unclassifiable	No	Yes
	Cambalache 3 GT	83	Diesel	Attainment/Unclassifiable	No	Yes
	Mayagüez 1 GT	50	Diesel	Attainment/Unclassifiable	No	Yes
	Mayagüez 2 GT	50	Diesel	Attainment/Unclassifiable	No	Yes
	Mayagüez 3 GT	50	Diesel	Attainment/Unclassifiable	No	Yes
	Mayagüez 4 GT	50	Diesel	Attainment/Unclassifiable	No	Yes
	Daguao 2 GTs	42	Diesel	Attainment/Unclassifiable	No	Yes
	Palo Seco GT11, 12	42	Diesel	Nonattainment	No	Yes
	Palo Seco GT21, 22	42	Diesel	Nonattainment	No	Yes
	Palo Seco GT31, 32	42	Diesel	Nonattainment	No	Yes
	Aguirre GT21 & 22	42	Diesel	Nonattainment	No	Yes
	Costa Sur GT11, 12	42	Diesel	Attainment/Unclassifiable	No	Yes
	Jobos GT11, 12	42	Diesel	Attainment/Unclassifiable	No	Yes
	Yabucoa GT11, 12	42	Diesel	Attainment/Unclassifiable	No	Yes
	Vega Baja GT11, 12	42	Diesel	Attainment/Unclassifiable	No	Yes
Hydro	Hydro (various)	34	Water	NA	No	No
IPP units	AES Coal Plant	454	Coal	Attainment/Unclassifiable	Yes**	Yes
	EcoEléctrica Plant	507	Natural Gas	NA	No	Yes

* Costa Sur 3 and 4 ST, Palo Seco 1 and 2 ST, and San Juan 9 and 10 ST listed here will not be included in the IRP analysis as future generating resources.

**MATS affected unit, however, PREPA is not responsible for compliance with MATS

Source: EPA, PREPA, Siemens

[22] Cambalache 1 GT, an 83MW diesel fired gas turbine, is currently out of service and is not assumed to be operational in the future in the IRP.

4.3.1 National Ambient Air Quality Standards (NAAQS)

The U.S. EPA sets standards for six criteria pollutants[23] under the Clean Air Act (CAA) and is required to regularly review and update these standards as necessary. Particulate matter, nitrogen oxides and sulfur dioxide (SO_2) are criteria pollutants emitted from fossil fuel combustion. Ozone levels can indirectly be impacted by fossil fuel emissions. No recent changes have been made to NAAQS for particulate matter and nitrogen oxides. Although the potential for these standards to change exists over the study horizon, no specific assumptions around these potential changes were made in modeling, given the uncertainty and overall expectation that the portfolio will become less fossil fuel based in the coming years.

4.3.2 SO_2 NAAQS

In January of 2018, EPA updated attainment designations for SO_2 for areas in Puerto Rico based on air quality modeling. The 1-hour SO_2 standard of 75 parts per billion was finalized in June 2010; however, the latest round of designations was published in January 2018 and became effective in April 2018. Several areas in Puerto Rico were designated as non-attainment areas, meaning that they were found not to meet the SO_2 standard. Other areas in Puerto Rico were designated as being in attainment or otherwise not able to be classified at this time. The designations are based on emissions from all sources of SO_2 emissions including transportation and industrial fuel use. For the IRP, the environmental review is focused on emissions from electric generating units. The combustion of coal- and petroleum-based fuels releases SO_2 emissions. Area designations for Puerto Rico are shown in the exhibits below.

Exhibit 4-21: Puerto Rico San Juan Area SO_2 Designations

Source: EPA

[23] The six criteria pollutants are ozone, particulate matter, carbon monoxide, nitrogen oxides, sulfur dioxide, and lead.

Exhibit 4-22: Puerto Rico Guayama Salinas Area SO_2 Designations

Source: EPA

In the San Juan area, the San Juan and Palo Seco generating facilities represent significant SO_2 emitting sources in the area. Actual historic emissions reported by PREPA are presented in Exhibit 4 17. Several industrial facilities emitting SO_2 are located in the San Juan area, all of which are reported by the EPA to emit less than 35 tons SO_2 annually. The San Juan Luis Munoz Marin Airport is also located in the San Juan area and is designated as a moderate source with annual emissions reported at 586 tons SO_2 in 2014. Another potentially large source of emissions in the area are the port and mobile sources such as is ship and vehicle traffic. In the Guayama Salinas area, the Aguirre generating facility is the most significant source contributor in the area. No other specific point sources were included in the Guayama Salinas area modeling analysis performed by the EPA in developing these designations. Aguirre historical emissions are also included in Exhibit 4 17.

Exhibit 4-23: Actual Reported SO_2 Emissions for PREPA Units in Nonattainment Areas (tons SO_2)[24]

Facility	Area	2013 Emissions	2014 Emissions	2015 Emissions
San Juan	San Juan	5,307	5,135	6,063
Palo Seco	San Juan	5,700	3,128	2,979
Aguirre	Guayama Salinas	9,640	9,261	9,585

Source: PREPA, EPA Technical Support Document Chapter 36, Final Round 3 Area Designations for the 2010 1-hour SO_2 Primary National Ambient Air Quality Standard for Puerto Rico

Units emitting SO_2 located in areas designated as attainment or unclassifiable will still continue to monitor and report emissions to the EPA, but do not otherwise have to alter operations at this time.

Units emitting SO_2 located in areas designated as nonattainment are required to be included in an SO_2 State Implementation Plan (SIP) that must be submitted to the EPA by Puerto Rico and finalized by October 2019. The Puerto Rico Environmental Quality Board (EQB) will develop the SIP, which will lay out a plan for how the nonattainment areas will achieve compliance with the SO_2 standard by 2023. Options for compliance for generating units include installation of sulfur emission control technology, fuel switching, or ceasing or reducing operations. Nonattainment designated areas are also subject to Nonattainment New Source Review requirements for permitting new and modified SO_2 emitting facilities in these areas.

PREPA units in locations classified as nonattainment for SO_2 are presented in the Exhibit below:

[24] Note that none of the PREPA units are equipped with continuous emission monitoring (CEMS). Emissions are estimated based on fuel specifications and hours of unit operation as reported by PREPA to the Puerto Rico EQB.

Exhibit 4-24: PREPA Units Included in Nonattainment SO_2 Standards Designation Areas

Area	Generation Units	Capacity (MW)	Fuel	SO2 EPA Final Designation
Guayama Salinas	Aguirre 1 ST	450	No. 6 fuel oil	Nonattainment
	Aguirre 2 ST	450	No. 6 fuel oil	Nonattainment
	Aguirre 1 CC	260	Diesel	Nonattainment
	Aguirre 2 CC	260	Diesel	Nonattainment
	Aguirre GT21 & 22	42	Diesel	Nonattainment
San Juan	Palo Seco 1 ST	85	No. 6 fuel oil	Nonattainment
	Palo Seco 2 ST	85	No. 6 fuel oil	Nonattainment
	Palo Seco 3 ST	216	No. 6 fuel oil	Nonattainment
	Palo Seco 4 ST	216	No. 6 fuel oil	Nonattainment
	Palo Seco GT11 & GT12	42	Diesel	Nonattainment
	Palo Seco GT21 & GT 22	42	Diesel	Nonattainment
	Palo Seco GT31 & GT32	42	Diesel	Nonattainment
	San Juan 5 CC	200	Diesel	Nonattainment
	San Juan 6 CC	200	Diesel	Nonattainment
	San Juan 7 ST	100	No. 6 fuel oil	Nonattainment
	San Juan 8 ST	100	No. 6 fuel oil	Nonattainment
	San Juan 9 ST	100	No. 6 fuel oil	Nonattainment
	San Juan 10 ST	100	No. 6 fuel oil	Nonattainment

Source: EPA, PREPA

Details on the Puerto Rico SIP will be updated by the results of the IRP analysis. The IRP will track SO_2 emissions from each portfolio and offer options for fuel switching (i.e. should natural gas become available in the north) and operational changes (i.e. minimum run or retirement and replacement with lower emitting generation options) to existing units. Facility-level operation and emissions resulting from the preferred portfolios will be provided to the Puerto Rico EQB. At this time, the following assumptions in the IRP analysis are expected to support emission reductions from these facilities:

- Palo Seco steam units 1 and 2 will not be assumed as future generating resources in the IRP analysis.
- Two of the San Juan steam units, 7, 8, 9 or 10, will not be assumed as future generating resources in the IRP analysis.

4.3.3 Mercury and Air Toxics Standards (MATS)

The EPA regulates emissions of hazardous pollutants from electric generating units. EPA's Mercury and Air Toxics Standards (MATS), originally issued in February 2012, imposes emission reductions of mercury, acid gases, and particulate matter, and also requires subject facilities to comply with work practice standards. This is a technology-forcing regulation with no allowance trading. The rule came into effect in April of 2015 and existing plants can apply for a one year extension to reach compliance. PREPA applied for and received a one-year compliance extension for Aguirre. The

MATS rule sets a decision point for generators – control or retires – even if cost drivers may come after 2016.

Several groups filed lawsuits challenging various aspects of the MATS rule, including the EPA's determination that it was appropriate and necessary to regulate emissions from power plants. On June 29, 2015, the Supreme Court of the United States found it unreasonable that the EPA did not consider costs in its initial finding that it was appropriate and necessary to regulate these emissions,[25] and the case was remanded to the D.C. Circuit Court of Appeals for further review. The D.C. Circuit remanded the proceeding to EPA to make a finding on the costs issue without vacating the MATS rule, and the MATS rule remains in effect. In April 2016, EPA published a final supplemental finding that it is appropriate and necessary to regulate hazardous air pollution from coal and oil fired steam EGUs, finding that the consideration of costs does not alter its initial finding that these emissions are necessary to regulate.[26] Therefore, steam coal- and oil-fired power plants continue to be legally obligated to meet the MATS standards.

PREPA units subject to MATS are presented in the exhibit below and the approach taken by each unit to comply with MATS.

[25] *Michigan et al. v. Environmental Protection Agency et al.*, 135 S.Ct. 2699 (2015).

[26] On December 27, 2018, EPA proposed to revise the April 2016 supplemental cost finding for MATS in order to correct what EPA deems to be flaws in the analysis. EPA proposes to determine that it is not "appropriate and necessary" to regulate hazardous air pollutant emissions from power plants under Section 112 of the CAA. EPA's proposal also states that the emission standards and other requirements of the MATS rule would remain in place, since EPA is not proposing to remove coal- and oil-fired power plants from the list of sources that are regulated under Section 112 of the Act at this time. However, EPA requests comment on whether the EPA has the authority or obligation to delist the source category and rescind the standards, or to rescind the standards without delisting.

Exhibit 4-25: PREPA Existing Units Subject to MATS

	Generation Units	Fuel	MATS Compliance Status
MATS Affected Units (PREPA Responsible for Compliance)	Aguirre 1 ST	No. 6 fuel oil	No quarterly test performed until Q4 2018(1)
	Aguirre 2 ST	No. 6 fuel oil	No quarterly test performed until Q4 2018(1)
	Costa Sur 3 ST	No. 6 fuel oil	This unit is currently not operating and will not be considered as a future generating resource in the IRP
	Costa Sur 4 ST	No. 6 fuel oil	This unit is currently not operating and will not be considered as a future generating resource in the IRP
	Costa Sur 5 ST	Natural gas(No. 6 fuel oil capable)	MATS compliant – now operating on natural gas
	Costa Sur 6 ST	Natural gas(No. 6 fuel oil capable)	MATS compliant – now operating on natural gas
	Palo Seco 1 ST	No. 6 fuel oil	Designated as limited-use unit but has exceeded heat-input threshold for limited use. This unit is currently not operating and will not be considered as a future generating resource in the IRP
	Palo Seco 2 ST	No. 6 fuel oil	Designated as limited-use unit but has previously exceeded heat-input threshold for limited use. This unit is currently not operating and will not be considered as a future generating resource in the IRP
	Palo Seco 3 ST	No. 6 fuel oil	PM emissions above MATS limit(2)
	Palo Seco 4 ST	No. 6 fuel oil	This unit is currently not operating(2)
	San Juan 7 ST	No. 6 fuel oil	Designated as limited-use unit but has exceeded heat-input threshold for limited use units. Modeled as running for reliability considerations in place of San Juan 9 (2)
	San Juan 8 ST	No. 6 fuel oil	Designated as limited-use unit but has exceeded heat-input threshold for limited use units. Modeled as running for reliability considerations in place of San Juan 10 (2)
	San Juan 9 ST	No. 6 fuel oil	PM emissions above MATS limit. Will not be considered as a future generating resource in the IRP
	San Juan 10 ST	No. 6 fuel oil	This unit is currently not operating. Will not be considered as a future generating resource in the IRP
MATS Affected Units (PREPA not Accountable for Compliance)	AES Coal Plant	Coal	Power Purchase - PREPA is not responsible for MATS compliance, AES represents that the plant is MATS compliant

Aguirre 1 & 2 are the largest single units in the system and are required to meet the load. Aguirre 1 & 2 can be made MATS compliant by their conversion to natural gas or can be retired (or designated limited use), when new generation is installed in the system.

These units in the north of the island are required to manage transmission limitations and can be retired (or designated limited use) when new generation is commissioned in the north.

Source: EPA, PREPA

The IRP analysis includes the following for MATS affected units:

- Aguirre units 1 and 2 are currently operating and are not MATS compliant. At this time, these units are required for reliability. Future resource portfolios will assume that these units only operate as needed for reliability purposes and then cease their operations as a means to comply with MATS. Conversion to natural gas was included as an option in Scenario 5. These units continue to operate under a 1999 consent decree with EPA. Additional action may be required pending the EPA's review of the results of the IRP. The IRP assumes that the units could run until 2025, when new large combined cycle plants could be in service.

- Costa Sur units 5 and 6 are complying with MATS by fuel switching, operating on natural gas. As of May 2018, these units began operating on natural gas. However, the permit still allows the units to operate on no. 6 fuel oil.

- Costa Sur steam units 3 and 4 and Palo Seco steam units 1 and 2 are not currently in operation and will not be considered as future generating resources in the IRP.

- Palo Seco Unit 4 and San Juan Unit 10 are currently not in operation. Palo Seco unit 3 and San Juan unit 9 have had PM emissions above the MATS limit and are run for reliability needs. San Juan Units 7-8 are designated as limited use units, which do not have to meet the MATS emission limits but must comply with certain work practice standards. San Juan Units 7-8 have previously exceeded the heat input limit for limited-use units, which require them to operate at less than eight percent capacity factor, averaged over 24-month block periods. San Juan units 9 and 10, interchangeable with units 7 and 8 for modeling purposes, will not be considered as a future resource in the IRP. The IRP assumes that the units could run until 2025, when new large combined cycle plants could be in service.

- New generating units included in the portfolio analysis are assumed to be MATS compliant.

Limited use and retirement options are also included in assessing portfolio options. PREPA will not consider investing in costly emission controls as a compliance option and therefore this was not considered in this analysis.

Other operational adjustments to comply with MATS have been considered but have been deemed through detailed conceptual analysis not to be viable compliance strategies for PREPA's units. Fuel blending was one compliance strategy assessed, as well as operational adjustments including infrequent soot blowing, higher burn point temperatures, and excess oxygen adjustments. Combinations of these operational adjustments have, albeit with significant challenges, enabled Hawaiian Electric Company (HECO) to comply with MATS. Characteristics of PREPA's units relative to HECO's units render them unsuitable to comply through these operational adjustments, including their larger size, lower burn temperatures, presence of continuous emission monitoring systems, mandated frequent soot blowing and higher average load levels. HECO also found fuel blending not to be a viable compliance strategy for its units. MATS compliance through fuel blending with ultralow sulfur diesel was considered by PREPA but was determined not to be a viable compliance option for MATS affected units in Puerto Rico based on PREPA's independent evaluations. In addition, based on information provided by PREPA, MATS compliance through operational modifications is not an option for the steam units.[27]

4.3.4 Summary of Environmental Permits and Expenditures for Generation

The following Exhibit summarizes the current status of the generation unit permits issues by the Puerto Rico EQB. The NAAQS Non-attainment designation gives PREPA until April 9, 2023 to be in compliance.

[27] Memorandum, "Staff Opinion – Assessment of Fuel Blending for MATS Compliance", Puerto Rico Electric Authority, July 25, 2018

Exhibit 4-26:Summary of Puerto Rico EQB Permit Status

Plant	Permit Number	Effective Date	Expiration Date	Permit Renewal Application	Protective Coverage Issued by EQB	New Permit Issued by EQB
Aguirre Power Complex	PFE-TV-4911-63-0796-0005 PFE-TV-4911-63-0212-0044	16-Mar-15	16-Mar-20	15-Apr-19	-	No
Costa Sur	PFE-TV-4911-31-0306-0429 PFE-TV-4911-31-0397-0021	24-Feb-02	24-Feb-07	26-Feb-06	23-Jun-06	No
Palo Seco	PFE-TV-4911-170-1196-0015	16-Mar-15	16-Mar-20	16-Mar-19	-	No
San Juan	PFE-TV-4911-65-1196-0016	31-May-05	31-May-10	31-May-09	2-Nov-09	No
Cambalache	PFE-TV-4911-07-0897-0043 PFE-TV-4911-07-0609-0215	31-May-05	31-May-10	29-May-09	-	No
Mayagüez	PFE-TV-4911-07-1196-0014 PFE-TV-4911-50-1105-1925	10-Nov-01	10-Nov-06	-	4-Mar-08	No
Daguao	PFE-TV-4911-19-0306-0447	14-May-10	14-May-15	14-May-14	5-Aug-14	No
Jobos	PFE-TV-4911-30-1107-0991 PFE-TV-4911-30-0914-0939	30-Sep-10	30-Sep-15	26-Sep-14	4-Nov-14	No
Vega Baja Turbines	PFE-TV-4911-74-0106-0021 PFE-TV-4911-74-1014-1016	30-Nov-10	30-Nov-15	20-Oct-14	4-Nov-14	No
Yabucoa Turbines	PFE-TV-4911-77-0397-0019 PFE-TV-4911-77-0707-0459 PFE-TV-4911-77-1216-0974	31-Dec-12	31-Dec-17	14-Dec-16	18-Jan-17	No

Source Workpaper: Source Workpaper: Renewal Dates for Operational Permits.xlsx

PREPA current pays $1,500,000 in Annual Emissions for all the facilities, except Cambalache. Last payment for Cambalache was the 2016 Annual Emissions in the amount of $13,107.25. We haven't received invoices from EQB for the 2017 & 2018 periods.

There are no current capital projects planned associated with environmental compliance for the requirements discussed above or for Mercury and Air Toxics Standards (MATS) or carbon regulation discussed below. However, planned transformation of the PREPA supply fleet, with the unit retirements, fuel conversions and renewable additions will all assist PREPA with reaching and maintaining fleet-wide environmental compliance.

4.3.5 Carbon Regulation

No economy-wide national regulation of carbon emissions exists in the in the U.S. at this time. In December 2009, EPA finalized its endangerment finding for GHG emissions from mobile sources, officially giving it the authority to regulate these emissions under the Clean Air (CAA). Beginning January 1, 2010, major stationary sources were required to track and report their annual GHG emissions to EPA. The EPA has issued regulations regulating the GHG emissions of new, modified, and existing electric generating units. An overview of these regulations, current status and applicability to this IRP are presented below.

4.3.6 New Source Performance Standards for GHGs for Electric Generating Units

In October 2015, EPA finalized New Source Performance Standards (NSPS) for Electric Utility Generating Units under §111(b) of the CAA, a proposed regulation that would establish carbon dioxide (CO_2) emission limits for certain new, modified, and reconstructed power plants in the U.S. The NSPS applies to new, reconstructed, or modified steam EGUs and to new or reconstructed

natural gas combustion turbines. The NSPS sets a rate limit of 1,000lbs of CO_2/MWh for combined cycle natural gas plants and a limit of 1,400lbs of CO_2/MWh for coal plants. The NSPS effectively prevents the permitting of new coal-fired power plants that are not equipped with CO_2 pollution control equipment such as carbon capture and sequestration (CCS), a technology that has yet to be deployed on a commercial scale.

In December 2018, EPA issued a proposed rule to amend the Section 111(b) standards for GHGs. The main feature of this proposal is that it would change the best system of emission reduction ("BSER") and emissions standards for steam EGUs. EPA did not propose changes to the NSPS for newly constructed or reconstructed natural gas stationary combustion turbines, as a part of the proposal.

Even if the rule is not amended, it is not anticipated to have a significant impact in PREPA's future generation portfolio. No new coal is expected. Even in the absence of this rule, Pace Global does not expect any build out of additional coal capacity in the near future. Other natural gas and fossil fuel fired units would be expected to need to meet these new source standards.

4.3.7 Clean Power Plan and Affordable Clean Energy Rule – GHG Emissions Guidelines for Existing Electric Generating Units

In October 2015, EPA finalized the Clean Power Plan (CPP), which established emissions guidelines for certain existing electric generating units under §111(d) of the CAA. The CPP established state by state emission targets for affected existing generation units. Under the CPP, states would determine the approach to meet their emissions goal, including choosing to comply as a rate goal (lb. CO_2/MWh) or a mass goal (short tons of CO_2). Overall, the aggregate state goals (on a mass basis) would reduce emissions from affected sources by an estimated 32% below 2005 levels by 2030. The initial compliance period would have begun in 2022, with the final reduction goal to be achieved by 2030. Trading of emissions between states would be encouraged under the CPP. It should be noted that Puerto Rico was not covered under the final CPP. Draft standards for existing generators located on Indian Country and in the U.S. Territories, including Puerto Rico, were released in 2014, but were never finalized. The final CPP noted that additional data would be needed to define final standards for these areas.

In February of 2016, the Supreme Court granted a request to stay the CPP while the courts rule on the legal challenges to the rule, rendering the rule and all associated planning deadlines not in effect until further notice. Further, the Trump Administration directed the EPA to perform a detailed review of the rule in a March 2017 Executive Order. This review resulted in a proposal to withdrawal the CPP in its entirety. Moreover, on August 31, 2018, EPA published the Notice of Proposed Rulemaking for the rule to replace the CPP—the "Affordable Clean Energy" or "ACE" rule. The Proposed ACE rule to replace the Clean Power Plan also currently proposes that emissions guidelines would not apply to Puerto Rico. However, until the final proposal is issued, the regulatory status remains uncertain.

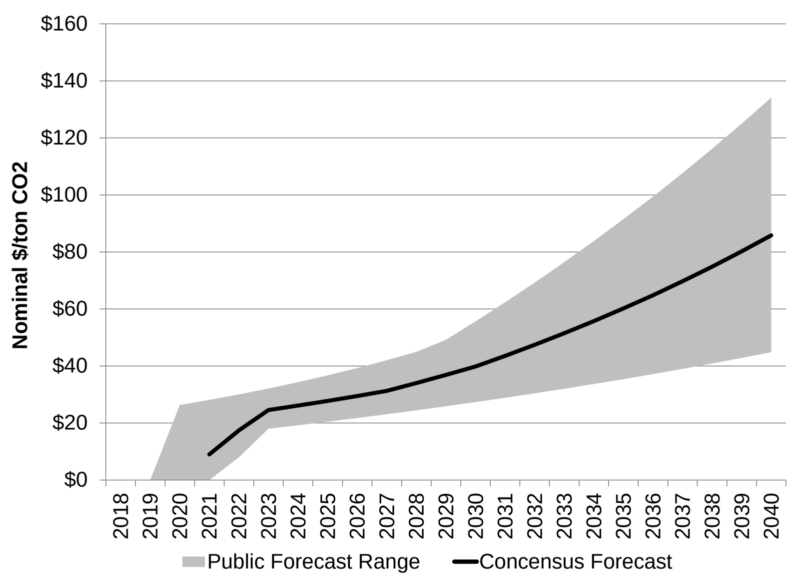
Given the pending proposals to withdraw and replace the CPP, a great deal of uncertainty exists at this time over the future of regulations covering CO_2 emissions from existing power generators. Because Puerto Rico was not regulated under the final CPP and the prevailing expectation is that the CPP rule will be withdrawn in its entirety, the CPP does not impact this IRP. Sensitivity analysis considered for this IRP would assess the impacts of a policy placing a price on carbon in the IRP.

4.3.8 Consideration of the Effect of Future Regulation of Carbon on Generators in Puerto Rico

Despite the absence of the CPP or any other national regulation of carbon emissions from power generators at this time, the potential for enactment of such regulation over the study horizon remains. To account for this uncertainty in the IRP analysis, sensitivities could be considered in supplemental analysis to include a price on CO_2 emissions from fossil generators.

This price on carbon is not intended to represent a specific view on an expected future national carbon program. The structure, timing, and resulting requirements of a potential future program are not known at this time. Rather this price could represent a future carbon trading or carbon tax policy and is intended to analyze the implications that a price on carbon would have on PREPA's portfolio operation and resource decisions. The carbon price considered for the potential sensitivity analysis is based on variety of publicly available sources and is presented in the exhibit below along with the range of pricing represented in public sources referenced.

Exhibit 4-27: Carbon Price – Carbon Regulation Sensitivities



Source: U.S. Energy Information Administration, Synapse, IHS, Siemens

4.3.9 Puerto Rico RPS

Renewable Portfolio Standards (RPS) are regulated programs placing an obligation on electricity suppliers that a certain percentage of their electricity sold be derived from alternative or renewable energy resources. At this time, 29 states, Puerto Rico, and the District of Columbia have enacted mandatory state-level RPS requirements. These RPS rules dictate expansion options and economics.

Puerto Rico firs IRPS was established by Act 82-2010 in July of 2010 and recently amended by Act 17-2019 which set minimum targets of renewable and alternative energy and puts the island on a path to 100% renewable generation by 2050. The targets set by the Act are a minimum of

- 40 percent on or before 2025

- 60 percent on or before 2040
- 100 percent on or before 2050

RPS mandates in general require that load serving entities to supply increasing shares of retail sales with qualified renewable and alternative source. This can be procured by direct purchase of the energy including renewable attributes or by the purchase of renewable energy certificates (RECs), which are tradable instruments representing the renewable attributes qualified generation, unbundled from the energy itself. RECs allow for compliance flexibility and in general can be banked for use up to two years forward.

Eligible renewable generation technologies include wind, solar, geothermal, renewable biomass or biofuel, new hydropower. Alternative renewable energy generation technologies that can also be used to meet the requirement include landfill gas, fuel cells, and municipal solid waste. The rules around the use of net metered renewable energy can be used for RPS compliance, however the pricing of the associated REC's of this distributed is to be determined.

The LTCE had as an input compliance with Act 17-2019 RPS and an intermediate target of 15% by 2021.

4.3.10 Clean Water Act Section 316(b)

The EPA issued the final standards for cooling water intake structures under Section 316(b) of the Clean Water Act in May 2014. This rule aims to reduce the impingement and entrainment of marine life from the impacts of water intake structures. This rule applies to industrial facilities, including electric generation facilities, that intake water for operation from bodies of water (i.e. lakes, rivers, estuaries, and oceans) exceeding two million gallons per day and of which 25 percent is used exclusively for cooling purposes. Covered facilities are required to obtain a National Pollutant Discharge Elimination System (NPDES) permit. Further requirements are based on water withdrawal levels.

- 2 million gallon per day – action to reduce the adverse impact to marine life including control technologies like velocity screens and implement biological impact monitoring at the intake structures
- 125 million gallon per day – additional assessments of impacts required to assess permit requirements
- New systems – review on facility will be conducted to assess controls needed, this applies to new facilities and expansions at existing facilities that would significantly increase water intake volumes

Noting the unique design of individual facilities, the rule is not prescriptive of controls required, rather assigns the permitting agencies the ultimate discretion in individual facility requirements.

All PREPA generating facilities operate under site-level NPDES permits. Through these permits, information requested to assess facility control needs to comply with 316(b) are being considered. Any new or facility expansions that impact water intake will be designed to comply with requirements under 316(b).

4.3.11 Puerto Rico Water Quality Standards Regulation

Section 304(a) of the CWA requires the EPA to publish water quality criteria based on the latest scientific review. These criteria can then be used by states to adopt or build on to define state specific water quality standards as a requirement of the CWA under Section 303(c).

The Puerto Rico EQB publishes and maintains Water Quality Standards Regulation to protect preserve, maintain and enhance the quality of water in Puerto Rico compatible with the social and economic needs of the Commonwealth. The latest standards were updated in April 2016. Specifically, this regulation designates uses for bodies of water, define water quality standards, identify rules and standards applicable to sources of pollution, and establish other measures deemed necessary to maintain water quality.

All existing generation facilities that have intake cooling water, discharge, or otherwise trigger requirements under the Water Quality Standards Regulation operate under NPDES permits. These permits document facility specific requirements and tolerances based on the applicable regulation and further informed by stakeholder input. Permitting for new facilities is outside of the scope of the IRP. However, new generation options considered as a part of the IRP analysis will assume reasonable levels of controls that would expected to comply with applicable water quality requirements for new sources in Puerto Rico.

Part

5

Resource Needs Assessment

5.1 Overview of the Needs

Resource planning is a multifaceted and technically complex process for most utilities. However, Puerto Rico and PREPA have a particularly complex resource planning environment due to numerous factors, including the isolated island operation without electrical or fuel delivery connections to other locations, the significant age and poor condition of much of the existing generation fleet, the uncertainty of the future economic conditions which greatly impact the electric generation requirements, and the vulnerability of the territory to catastrophic weather events. While many utilities are looking for ways to make incremental changes to their system to enhance their resiliency, the devastation to PREPA's electrical infrastructure from the 2017 Hurricanes forced PREPA to rethink its entire system design including resource planning. This IRP, following on the heels of one of the worst storm related outages experienced by an electric utility, offers PREPA an opportunity to define a sharp and significant improvement in direction for the future energy supply of Puerto Rico.

Further to the above, 2019 IRP is not a classical IRP designed to identify the least cost approach to address the expected gap between load and resources and maintaining a desired Planning Reserve Margin (PRM), but rather produce a plan that satisfies the objectives of being customer centric, financial viability, reliability and resiliency and economic growth, on a context of significant declines in the load.

Thus, this IRP is designed instead, to address the following resource needs:

a) Address the impacts of an aging generation infrastructure that burns costly liquid fuels (mostly heavy fuel oil), which has poor reliability, does not meet environmental regulations (e.g. MATS) and is inflexible, which limits the incorporation of renewable resources.

b) Achieve a reduction of cost of supply by the incorporation of renewable resources and take advantage of the currently observed and forecasted reduction in cost.

c) Achieve compliance with RPS mandate. However, Siemens observed that economies alone justified significant levels of penetration.

d) Shift from centralized generation located in the south of the island to a more decentralized generation mix, with resources across the island.

Taking in consideration the above, through input received during a series of Stakeholder Workshops, discussion with PREPA staff and Siemens own knowledge and experience with resource planning, the PREPA and Siemens project team defined a number of aspects that the resource planning resulting from this IRP must address. These needs included but were not limited to:

- Reduce the dependence on an aging, inflexible and not reliable fleet and move away from the reliance on large, concentrated generating plants.
- Improve the overall resiliency of the system to better enable Puerto Rico to withstand and recover from future severe weather and other disruptive events.
- Improve the sustainability of the electrical end use and supply.
- Determine the role of natural gas in PREPA future resource supply.
- Include in the analysis, the uncertainty associated with load, fuel costs and costs of supply technologies.
- Create a resource plan that addresses the needed changes while balancing the cost of service to customers.
- Deliver a transparent planning process that allows stakeholders to review and understand the planning process and recommendations.
- Preserve optionality through preliminary development and permitting activities to provide contingency for deviations in load projections.

In the balance of this section Siemens present the strategies, Scenarios and sensitivities used to formulate the multiple long term capacity expansion plans to address the needs above.

5.2 Three Strategies

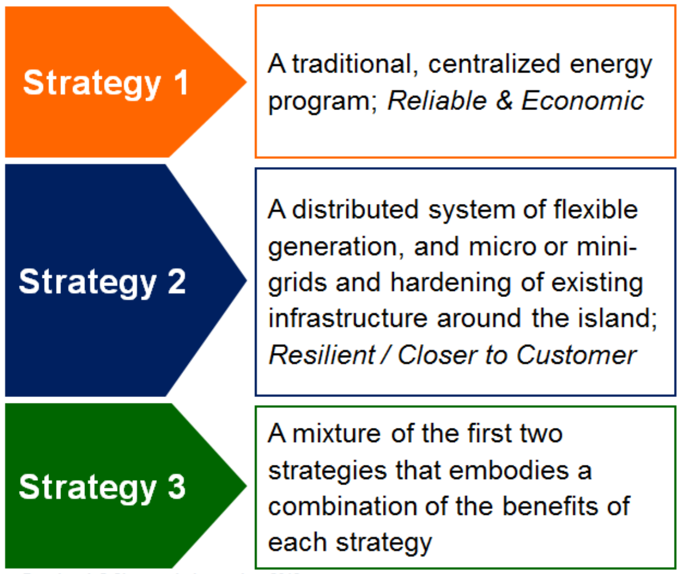
As part of the stakeholder process, Siemens shared three potential strategies for consideration as shown below.

Strategy 1 reflects a traditional and centralized energy program that emphasizes reliability and economic metrics.

Strategy 2 reflects a distributed system of flexible generation, and micro or mini-grids and hardening of existing infrastructure around Puerto Rico, which emphasizes resiliency and closeness to the customer. In this strategy, most of the load is supplied from local supply resources that can be isolated from the remainder of island during a major event but still supply all or a portion of the nearby load. It is defined in terms of a minimum level of the load to be supplied by local resources (e.g., 80%).

Strategy 3 reflects a hybrid of the first two strategies that embodies a combination of the benefits of Strategy 1 and Strategy 2. In this strategy, economies of scale are taken advantage of, and some of the load may be served under normal conditions from remote resources. In this strategy, the potential for greater levels of rotating load shed during a major event is greater than Strategy 2 but should result in lower operating costs.

Exhibit 5-1. PREPA IRP Strategies



To achieve the vision of a more renewable, resilient, and reliable Puerto Rico electric system, the IRP incorporates analysis of mini-grids, micro-grids, and grid modernization to systematically improve resiliency with pockets of critical loads served by distributed resources that can operate in both grid-connected and island modes. These mini-grids are proposed to be strategically sited to support clusters of critical transmission and distribution voltage loads, downstream of distribution and transmission vulnerabilities. The IRP seeks to balance low cost reliable operation under normal conditions and the ability to mitigate and achieve timely recovery from major disruptive events.

Stakeholders generally reached consensus that a strategy founded on distributed rather than centralized supply resources is more appropriate to Puerto Rico's situation because it provides a more resilient grid. Generally, participants viewed Strategy 3 ("hybrid strategy" of centralized and distributed generation) as a short- or medium-term step to Strategy 2 (a long-term mix of distributed and flexible generation in Puerto Rico where supply is located closer to load). Most stakeholders did not support pursuit of the centralized Strategy 1, except possibly as a reference point for comparison. On the other hand, some stakeholder groups requested that Strategy 1 be explicitly modeled as this strategy was thought to likely provide the least cost configuration. Larger centralized resources aligned with Strategy 1 were incorporated in the Scenario that has all resources competing to provide the desired cost comparison information.

In addition to the IRP Regulation effective since April 24, 2018, the PREB issued orders on September 5 and September 18, 2018, and later dates, regarding Scenarios and other points of the IRP, including, but not limited to, a directive to consider Strategy 1. The regulation and orders speak for themselves, so they will not be summarized here, although some of them are referenced below.

For each strategy, a combination of assets was developed by putting constraints on the generation, transmission, and distribution assets that are available to Puerto Rico for a specific strategy. For example, a fully distributed strategy did not consider traditional high capacity generating assets such as large gas fueled combined cycle plants or diesel fueled assets. A partially distributed system or hybrid system considered only a limited amount of larger traditional generators.

5.3 Uncertainties

In addition, the IRP captures a series of uncertainties, including load growth, renewable generation O&M[28] and capital costs, fuel availability and price forecasts, energy policy and permitting, weather, energy efficiency, and PPOA termination or extension. The Scenarios and sensitivities are designed to test each strategy against a combination of these uncertainties. The Scenarios and sensitivities, are discussed below.

5.4 Scenarios

The PREB IRP Regulation defines Scenarios as a combination of system requirements needed to serve load, commodity prices, capital costs, and risks that influence the choice of resources serving PREPA's future load. Each Scenario constitutes a possible resource plan. Traditional uncertainties (e.g., load forecasts, fuel forecasts, and renewables capital costs) are assessed via cases (High, Base and Low) and sensitivities. They could also be assessed via stochastic analysis. Based on extensive stakeholder engagement and consolidation of the September Scenarios orders by PREB, PREPA considered a total of six Scenarios as part of the 2018-2019 IRP.

With respect of fuel infrastructure and renewables, the following Scenarios are considered as outlined in Exhibit 5-2 and further described below.

Scenario 1: No new gas-fired generation is installed. The Scenario uses the base case assumptions of solar and storage costs and availability. The only new gas generation considered in this scenario is the conversion of the combined cycle at San Juan 5 & 6.

Scenario 2: Gas to North: The land-based LNG at San Juan in the North is assumed to acquire the required permitting approval. The Scenario uses the base case assumption of solar and storage costs and availability. This scenario was eventually dropped as Scenario 4 collapsed to the same conditions in this scenario; only gas was developed in the north and the south.

Scenario 3: Gas to Yabucoa (east) and to Mayagüez (west) through ship-based LNG and gas to the north is supplied through land-based LNG at San Juan. The land-based LNG at San Juan is assumed to acquire the required permitting approval. The Scenario assumes the deeper drop (NREL Low Case) of solar and storage costs coupled with high availability of renewables (early ramp up).

Scenario 4: Gas to Yabucoa (east) and to Mayagüez (west) through ship-based LNG and gas to the north is supplied through land-based LNG at San Juan. The land-based LNG at San Juan is assumed to acquire the required permitting approval. The Scenario uses the base case assumption of solar and storage costs and availability.

Scenario 5: Aguirre Offshore Gas Port (AOGP), gas to Yabucoa (east) and to Mayagüez (west) is supplied through ship-based LNG. Gas to the north is supplied through land-based LNG at San Juan which is assumed to achieve required permitting approval. The Scenario uses the base case assumption of solar and storage costs and availability. The Scenario also places no restriction on the size of the combined cycle units (CCGT)

[28] Operation and maintenance

and up to H-Class (449 MW) could be added. All previous Scenarios had a maximum size of 302 MW F-Class CCGT. The scenario eventually did not select the AOGP, thus confirming that other options modeled were superior.

ESM: Energy System Modernization (ESM); this is a variation of Scenario 4 advanced by PREPA and that includes a set of pre-defined investments decisions that considers procurement options presented by the Public Private Partnership Authority, pricing structures necessary to retain existing natural-gas fired generation in the south, and locational alternatives for new large scale CCGTs. The ESM is benchmarked against the formulated least cost plans. See further details below.

Exhibit 5-2. PREPA IRP Scenario Definition

Scenario	New Gas				Renewable & Storage	
	AOGP	Land-based LNG at San Juan	Ship-based LNG at Yabucoa	Ship-based LNG at Mayagüez	Costs	Availability
1	No	No	No	No	Reference	Reference
2	No	Yes	No	No	Reference	Reference
3	No	Yes	Yes	Yes	Low	High
4	No	Yes	Yes	Yes	Reference	Reference
5	Yes	Yes	Yes	Yes	Reference	Reference
ESM	No	Yes	Yes	Yes	Reference	Reference

The ESM plan has some decisions that are fixed and not subject to the LTCE selection. This includes a land based LNG terminal at San Juan and a new 302 MW Combined Cycle Gas Turbine (CCGT) to be developed at Palo Seco by 2025 (or as early as possible); these investments will follow the conversion of San Juan 5&6 to gas (in 2019), which will be supported initially by a ship-based LNG that will be replaced by the land-based when commissioned. At Yabucoa a Ship-Based LNG terminal is to be developed and 302 MW CCGT is installed by 2025 (or as early as possible). At Mayagüez, a Ship-Based LNG terminal is developed, but the only fix decision is to convert the existing 4x50 MW aeroderivative units to be able to burn natural gas.

As was the case of all other scenarios, the ESM plan was assessed using a capacity expansion model, to determine, in addition to the “fixed” decisions above, the timing of and amounts of other resources including Photovoltaic (PV) generation, wind turbine generation, additional thermal generation (e.g. the possibility of installing a CCGT at Mayaguez) and the economic retirements of the existing generating fleet. The workpaper “Considerations on the ESM Plan” provides further details on the reasons behind the fixed decisions of the plan.

The following conditions and assumptions, unless specifically indicated to the contrary, will be modeled across all five Scenarios and the ESM:

1. Load Forecast is treated via a Base, High and Low case. A stochastic analysis could be conducted as a follow-up analysis; however, as will be discussed later in this report, the High and Low cases allow identifying the decisions that would be affected by changes in the load growth and the path to account for this uncertainty.

2. Fuel forecast and costs of renewable and storage are treated via sensitivities and the modification on decisions identified.

3. The AES PPOA is assumed to expire in 2027 and not be renewed in accordance with the provisions of Act 17-2019. The EcoEléctrica PPOA is assumed to be renewed in 2022 with modifications on the contract to prevent the immediate retirement of the plan. These modifications were modeled as a reduction of the fixed payments and EcoEléctrica being able to cycle in and out of service as required to integrate renewable (see section 4.1.1.5 EcoEléctrica and AES PPOAs) . On the other hand, after expiration of the existing contract the energy payments are assumed to follow market conditions, instead of the reduced prices now in place.

4. Energy Efficiency is assumed to meet the requirement of the IRP Regulation of 2% per year incremental savings attributable to new energy efficiency programs.

5. Peaking generation was added to all LTCEs under Strategy 2 and Strategy 3 to ensure that the critical loads located in each of the recommended eight electric islands into which the system would be segregated after a major storm (the MiniGrids), could be served on grid isolated mode. This peaking generation along with the renewable generation and the storage in the MiniGrid would serve the priority loads and as much as possible of the balance of the load. Strategy 1 did not have this requirement and was used to identify the tradeoff between benefits and costs (value of loss load) of relying on central generation. The ESM had also these GT's as a fixed decision.

It should be noted that the possibility of achieving permitting approval for any of the LNG terminal above does not mean that the option of gas generation will be automatically selected nor its size.

5.5 Sensitivities

Sensitivity analyses were used to isolate the impacts of certain important variables while holding other assumptions constant. For the 2018 IRP, six sensitivities were included in the core scope of this study[29], as shown in Exhibit 5-3. PREPA IRP Sensitivity Definition and further described below

Sensitivity 1: Deeper reduction in cost of solar and storage, coupled with high availability of storage and solar. In Sensitivity 1, higher yearly limits of PV/BESS (photovoltaic / battery energy storage system) are assumed. See Exhibit 6-27 for the limits of this Sensitivity 1. As a reference, Exhibit 6-28 has the limits for the core LTCE and Exhibit 6-29 the limits for the ESM.

Sensitivity 2: Lower energy efficiency (EE) penetration (~1% reduction per year instead of 2%). This sensitivity was included in the previous filing of the IRP, prior Act 17-2019. Only EE materializations consistent with the Act 17-2019 were modeled.

Sensitivity 3: The Economic retirement of AES and EcoEléctrica regardless of contract term was analyzed as a sensitivity in the first filing of this IRP. Given the mandates of Act-17-2019, no extension of AES burning coal was assessed. EcoEléctrica was always modeled as being extended, subject to economic retirement.

[29] Once this study is completed, more sensitivities models and stochastic analysis could be run as well as running the core sensitivities on other strategies, as required by the PREB.

Sensitivity 4: Ship-based LNG at San Juan could achieve permitting approval. The ship-based LNG at San Juan can basically supply the conversion of San Juan 5&6 and provide limited gas to other developments. It has reduced capacity in comparison to the land-based LNG option.

Sensitivity 5: High gas prices.

Sensitivity 6: High cost of solar and storage.

Sensitivity 7: Applies to Scenario 1, no San Juan 5 & 6 conversion to gas.

Sensitivity 8: Applies to Scenario 3, base cost of renewable generation and storage.

Sensitivity 9: Applies to Scenario 4, EcoEléctrica forced not to retire and used to identify the actual reduction on fixed payments that makes the case equivalent to the situation where it is replaced.

Exhibit 5-3. PREPA IRP Sensitivity Definition Used

Sensitivity	Solar/BESS	Gas	Gas	Solar/BESS	Gas	Solar/BESS	PPOA
	Low Cost	Only Ship-based LNG at San Juan	High Gas Prices	High Cost	No Ship-Based LNG at SJ	Base Cost	EcoEléctrica Stays Online
1	◆						
4		◆					
5			◆				
6				◆			
7					◆		
8						◆	
9							◆

Additional important sensitivities were proposed by stakeholders, including no RPS (renewable portfolio standard) and/or postponed MATS compliance (US EPA Mercury and Air Toxics Standards regulation) to show the cost of compliance. However, all LTCE plans had economic developments close to the RPS limits. Also, most MATS incompliant units were retired on economics rather than compliance reasons, which forced the units to retire by 2025. The timing of unit retirements are predicated on new replacement resources and realization of load projections.

Finally, it is recognized that additional sensitivities could be included as gas to the north and south via pipelines, emissions prices (CO_2), and cost of capital.

5.6 Portfolio Cases

Portfolio cases are unique combinations of Scenarios and strategies. Exhibit 5-4below illustrates the 35 portfolio cases that were assessed. The portfolio cases are named under the convention of "Scenario ID + Strategy ID + Sensitivity ID + Load Forecast (High, Base or Low)".

It can be noted below that for Scenarios 1 to 4, the portfolios cases and the resulting LTCE plan is assessed for the High, Base, and Low load growth forecast for the Strategy the resulted in least cost. Strategy 2 and Strategy 3 are considered for the Scenarios 1 to 4 and as Scenario 5 is designed not to have any restrictions, the Strategy 1 is used.

Regarding the 35 portfolio cases and associated model treatment, the LTCE is run in all core scenarios and those sensitivities that change the availability of gas (Sensitivity 4 and 7). Other sensitivities to capital costs or fuel prices are carried out maintaining the expansion plan identified in the core run and for the strategy that resulted in least cost.

Exhibit 5-4. PREPA 2018 IRP Portfolio Cases Summary

Count	Case ID	Scenario	Strategy	Sensitivity	Load	AURORA LTCE
1	S1S2B	1	2		Base	Yes
2	S1S2H	1	2		High	Yes
3	S1S2L	1	2		Low	Yes
4	S1S3B	1	3		Base	Yes
5	S1S2S1B	1	2	1	Base	No
6	S1S2S5B	1	2	5	Base	No
7	S1S2S6B	1	2	6	Base	No
8	S1S2S7B	1	2	7	Base	Yes
9	S1S1B	1	1		Base	Yes
10	S3S2B	3	2		Base	Yes
11	S3S2H	3	2		High	Yes
12	S3S2L	3	2		Low	Yes
13	S3S3B	3	3		Base	Yes
14	S3S2S5B	3	2	5	Base	No
15	S3S2S8B	3	2	8	Base	No
16	S4S2B	4	2		Base	Yes
17	S4S2H	4	2		High	Yes
18	S4S2L	4	2		Low	Yes
19	S4S2S9B	4	2	9	Base	No
20	S4S3B	4	3		Base	Yes
21	S4S2S1B	4	2	1	Base	No
22	S4S2S4B	4	2	4	Base	Yes
23	S4S2S5B	4	2	5	Base	No
24	S4S2S6B	4	2	6	Base	No
25	S4S1B	4	1		Base	Yes
26	S5S1B	5	1		Base	Yes
27	S5S1S5B	5	1	5	Base	No
28	S5S1S1B	5	1	1	Base	No
29	S5S1S6B	5	1	6	Base	No
30	ESM				Base	Yes
31	ESM High				High	Yes
32	ESM Low				Low	Yes
33	ESMS1B			1	Base	No
34	ESMS6B			6	Base	No
35	ESMS5B			5	Base	No

Part
6

New Resource Options

6.1 Overview of New Generation Resources

Siemens and PREPA discussed the key criteria in developing new generation resources to allow for system flexibility and reliability, including the capability to accommodate large blocks of renewable capacity, primarily solar. Siemens conducted technology screening to identify technically feasible and commercially viable generation resources that could be used as building blocks in constructing generation asset portfolios. For this reason, the technology screening focuses on resource options that could meet PREPA's new generation resource requirements, including:

1. Size of the new generation resource, which is informed by factors including size of the maximum contingency and local reserve requirements, load profile, retirement of existing resources, and expiration of PPOA, etc.

2. Resource type: base load, intermediate, intermittent, or peaking resources, largely determined by renewable generation integration.

3. Characteristics: ramping rate and daily cycling capability.

4. Fuel type: fossil-fueled (natural gas, diesel or dual fuel with natural gas as primary and diesel as backup).

5. Local considerations: altitude, temperature, natural wind or solar resources, etc.

6. The technology selection on a broader perspective considered a combination of dispatchable fossil-fueled generation resources, storage and renewable technologies.

7. Utility scale solar and storage for new builds of renewable resources.

8. Fossil-fueled resources included CCGT, GT, reciprocating internal combustion engines (RICE), and CHP. Siemens relied upon information exchanged with PREPA, performance and cost information provided by vendors, as well as GT Pro[30] software performance and cost calculations in estimating representative generation resources.

6.2 Capital Cost Recovery Factors

[30] GT Pro is a software program licensed by Thermoflow for sizing and designing simple cycle, combined cycle, cogeneration, GT, CCGT, CHP, and other types of power generation units. GT Pro was used to determine, among other measures, plant output, heat rate, duct firing capacity, and capital costs for the specified site conditions and available fuels.

All new resources are assumed in this IRP that will be developed by third parties that will recover operating and maintenance cost and recover its capital expenditures via periodic payments from PREPA. To estimate the payments to recover the capital it is necessary to determine a Capital Cost Recovery (CCR) factor which is a function of the developer's WACC and the capital recovery period that is related with the expected life of the asset. These aspects are treated below.

6.2.1 Weighted Average Cost of Capital (WACC)

In the context of developing a consensus assumption of WACC among key stakeholders, Siemens acknowledges a few important factors impacting both the cost and availability of capital. With $9 billion debt outstanding, PREPA currently has no access to bond market and bank financing. In addition, recent Act 120-2018 authorized PREPA to sell its generating assets to potential private buyers.

Based on discussions with stakeholders, Siemens considers future builds to be financed by third parties and consider that PREPA obtain financial backing to contract as a credit-worthy counterparty, if and as needed. Exhibit 6-1 shows the component assumptions deriving a nominal weighted average cost of capital of 8.50%.

Exhibit 6-1. Weighted Average Cost of Capital Assumptions

Cost of Equity	
Asset Beta	0.70
Income Tax Rate	39.00%
Debt to Equity Ratio	0.90
Equity Beta	1.08
Risk-Free Rate	2.95%
Equity Risk Premium	5.50%
Company Specific Risk Premium	4.00%
Cost of Equity	12.91%
Cost of Debt	
Cost of Debt, Pre-tax	5.00%
Tax Rate	32.0%
Cost of Debt, After-tax	3.40%
Weighted Average Cost of Capital	
After-tax Cost of Debt	3.40%
Percent Debt	47%
Cost of Equity	12.91%
Percent Equity	53%
WACC	**8.50%**

See workpaper: CapitalCostRecoveryFaxtor.xlsx

Note: The corporate income tax rate is assumed based on a base rate of 20%, plus a graduated surcharge ranging from 5% to 19%[31].

[31] Deloitte International Tax Puerto Rico Highlights 2018

6.2.2 Cost of Capital Recovery Factor by asset class

The exhibit below shows per asset class the Capital Recovery Period (also known as the Economic Life) and the corresponding CCR Factor. With respect of the below it should be mentioned that given the mandates of Act-17-2019 that defines 2050 as a target for 100% renewable generation, the Capital Recovery Period of thermal generation is reduced as the development date is closer to 2050, so that the asset would be totally paid for at that time and could be retired.

Exhibit 6-2. Capital Cost Recovery Factor by Asset Class

Asset Class	Capital Recovery Period (Years)	CCR
Combined Cycle Plant	28	9.5%
Small Combined Cycle	20	10.6%
Existing Unit Fuel Conversion / Switching (San Juan)	21	10.4%
Solar PV /Wind	25	9.8%
Battery Storage	20	10.6%
LNG Terminal	22	9.8%

See workpaper: CapitalCostRecoveryFaxtor.xlsx

6.3 New Fossil-Fired Generation Resources

6.3.1 Generation Options Development and Sizing

A three-step process was used to determine generating unit characteristics and select technologies for portfolios as discussed below.

First, Siemens performed a technology screening. GTs and their corresponding CCGT plants come in discrete sizes based on equipment offerings from a limited number of worldwide manufacturers. Siemens' approach was to screen a large number of available GT and CCGT configurations from all major manufacturers like GE, Mitsubishi, Hitachi, Siemens, and Solar Turbines, based mainly on published performance of available GT and CCGT generating units at ISO conditions (59° F, 60 percent relative humidity, and sea level) with wet cooling towers on natural gas fuel. All CCGT cases were evaluated in 1 x 1 Power Block configuration, i.e., a single train of GT, Heat Recovery Steam Generator (HRSG) and Steam Turbine Generator (STG).[32] A limited number of cases from various manufacturers were selected for analysis in GT Pro software.

Second, from this group, certain configurations were selected for modeling in GT Pro to obtain performance specific to PREPA site conditions (85° F, 70 percent relative humidity, and 25 or 1,000 feet above mean sea level[33]) on natural gas and distillate oil (also known as Diesel or Light Fuel Oil - LFO), with and without duct firing, and with dry cooling as appropriate for the application. New

[32] 1 x 1 Power Block projects give siting flexibility in modeling. If multiple trains are needed in same location, later optimizations can be performed to evaluate whether 2 x 1 or 3 x 1 fit the operating profile and are more economic than 1 x 1.

[33] Large plants near coast were set at 25 ft AMSL to be above storm surge. Smaller plants that might be used at interior sites were set at 1,000 ft AMSL.

CCGTs assumed dry cooling with Air Cooled Condensers (ACCs). Siemens criterion was to design and size the plant based on liquid (distillate or diesel) fuel, then to determine corresponding performance of the same design operating on natural gas. It should be noted that this likely resulted in somewhat less attractive performance than for a plant designed solely for natural gas fuel. Future optimization is possible for Scenarios using CCGT with natural gas as primary fuel.

Finally, GT Pro performance estimates were used to select which configurations to consider in developing the generation portfolios for capacity expansion in AURORA and the subsequent nodal analysis in AURORA-Nodal.

When Siemens selected new generation options for inclusion in portfolios, a particular unit design based on an actual product is chosen as representative of a class of similar units. In all cases, there is at least one additional unit available from a different manufacturer with sufficiently similar characteristics that competitive bidding would be possible at the time a project is implemented. The important point is that the generating units used for the IRP purposes do not lock PREPA into any particular manufacturer for project implementation and further optimization can be achieved at the time of implementation.

For the RICE case, Siemens obtained published Wartsila performance information for a large engine capable of dual fuel (natural gas and diesel) operation. Siemens made a manual adjustment for site conditions. This engine requires about 0.5 to 1.0 percent diesel pilot fuel when operating on natural gas. Siemens made a small adjustment to the RICE natural gas heat rate to account for the higher cost of the pilot fuel.

All selected generation resources are analyzed based on dual fuel capability with natural gas and diesel, with gas being the primary fuel when available and an option when not. For dual fuel units, the unit output and heat rate are somewhat different depending on the fuel type. The representative options selected by Siemens are discussed in the next subsection.

6.3.2 Representative Future Generation Resources Characteristics

As indicated above, Siemens developed key operational parameters of the representative future generation resources, primarily relying on published vendor information as well as vendor-supplied performance and cost information available in GT Pro performance software.

Exhibit 6-1 presents the operational parameters for an H Class Combined Cycle (GE S107HA.01) unit. Exhibit 6-2 and Exhibit 6-3 present the operational parameters of a larger F-Class Combined Cycle (CCGT - GE S107F.05) unit and a smaller F-Class Combined Cycle (CCGT - GE S107F.04) unit, respectively. Exhibit 6-4 presents the operational parameters for medium-sized combined cycle (Hitachi H-100). These units have a short minimum run time and hence can cycle in and out of service daily. Also, the minimum capacity is 39 to 48 percent of the duct fired capacity allowing a significant reduction in output before the units must be turned off. In addition, the units can ramp up from their minimum to the maximum capacity in 3.5 to 8 minutes.

Exhibit 6-3. H Class Combined Cycle (GE S107HA.01)
Operational Assumptions

Generation Unit Type	Unit	H Class CC (GE S107HA.01)	
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	374	365
Max. Unit Capacity with Duct Fire	MW	449	438
Min. Unit Capacity	MW	176	172
Min. Unit Capacity (% of Duct F Capacity)	%	39%	39%
Fixed O&M Expense	2018 $/kW-year	22.09	22.09
Variable O&M Expense	2018 $/MWh	1.75	1.75
Heat Rate at 100% Rated Capacity (Unfired)	MMBtu/MWh	6.77	6.60
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	7.09	6.90
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	360	360
Unit Forced Outage Rate	%	2.0%	2.0%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	40	40
Ramp Down Rate	MW/minute	40	40
Regulation Minimum Range	MW	176	172
Regulation Maximum Range	MW	449	438
Regulation Ramp Rate	MW/minute	40	40

Exhibit 6-4. F-Class CCGT - Larger (GE S107F.05)
Operational Assumptions

Generation Unit Type	Unit	F Class CC - Larger (GE S107F.05)	
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	303	295
Max. Unit Capacity with Duct Fire	MW	369	361
Min. Unit Capacity	MW	172	168
Min. Unit Capacity (% of Duct F Capacity)	%	47%	47%
Fixed O&M Expense	2018 $/kW-year	22.09	22.09
Variable O&M Expense	2018 $/MWh	1.75	1.75
Heat Rate at 100% Rated Capacity (Unfired)	MMBtu/MWh	7.25	7.07
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	7.53	7.32
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	360	360
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	40	40
Ramp Down Rate	MW/minute	40	40
Regulation Minimum Range	MW	172	168
Regulation Maximum Range	MW	369	361
Regulation Ramp Rate	MW/minute	40	40

Exhibit 6-5. F-Class CCGT - Smaller (GE S107F.04) Operational Assumptions

Generation Unit Type	Unit	F Class CC - Smaller (GE S107F.04)	
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	251	245
Max. Unit Capacity with Duct Fire	MW	302	296
Min. Unit Capacity	MW	144	141
Min. Unit Capacity (% of Duct Fired Capacity	%	48%	48%
Fixed O&M Expense	2018 $/kW-year	22.09	22.09
Variable O&M Expense	2018 $/MWh	1.75	1.75
Heat Rate at 100% Rated Capacity (Unfired)	MMBtu/MWh	7.27	7.09
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	7.55	7.34
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	360	360
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	30	30
Ramp Down Rate	MW/minute	30	30
Regulation Minimum Range	MW	144	141
Regulation Maximum Range	MW	251	245
Regulation Ramp Rate	MW/minute	30	30

Exhibit 6-6. Medium CCGT Hitachi (H-100) Operational Assumptions

Generation Unit Type	Unit	Medium CC (Hitachi H-100)	
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	116	113
Max. Unit Capacity with Duct Fire	MW	144	141
Min. Unit Capacity	MW	61	60
Min. Unit Capacity (% of Duct F Capacity)	%	42%	42%
Fixed O&M Expense	2018 $/kW-year	33.12	33.12
Variable O&M Expense	2018 $/MWh	2.61	2.61
Heat Rate at 100% Rated Capacity (Unfired)	MMBtu/MWh	7.76	7.56
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	8.25	8.02
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	360	360
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	15	15
Ramp Down Rate	MW/minute	15	15
Regulation Minimum Range	MW	61	60
Regulation Maximum Range	MW	144	141
Regulation Ramp Rate	MW/minute	15	15

Exhibit 6-5, Exhibit 6-6 and Exhibit 6-7 present the operational parameters of the small combined cycle units (GE LM6000 DLE, GE LM2500+G4 SAC, and GE LM2500 SAC) considered in the IRP. As with the larger units, these units have a short minimum run time and can cycle in and out of service daily. Their minimum capacity is 42 to 51 percent of the duct fired capacity, allowing a significant reduction in output before the units must be turned off. These units can ramp up from their minimum to the maximum normal capacity in about 30 seconds. The GE LM2500+G4 SAC was

modeled with the capability of burning LPG and natural gas when offered as an option for the North and in the ESM, plan as discussed later in this report.

Exhibit 6-7. Small CCGT (GE LM6000 DLE) (Duct Fired)
Operational Assumptions

Generation Unit Type	Unit	Small CC (GE LM6000 DLE)	
		Natural Gas	Diesel
Max. Unit Capacity w/o Duct Fire	MW	51	49
Max. Unit Capacity with Duct Fire	MW	66	63
Min. Unit Capacity	MW	27	26
Min. Unit Capacity (% of Duct F Capacity)	%	42%	42%
Fixed O&M Expense	2018 $/kW-year	36.13	36.13
Variable O&M Expense	2018 $/MWh	5.29	5.29
Heat Rate at 100% Rated Capacity	MMBtu/MWh	7.83	7.65
Heat Rate at Full Duct Fire Capacity	MMBtu/MWh	8.62	8.37
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	180	180
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	50	50
Ramp Down Rate	MW/minute	50	50
Regulation Minimum Range	MW	27	26
Regulation Maximum Range	MW	66	63
Regulation Ramp Rate	MW/minute	50	50

Source: Siemens

Exhibit 6-8. Small CCGT (GE LM2500 +G4 SAC)
Operational Assumptions

Generation Unit Type	Unit	Small CC (GE LM2500+ G4 SAC)	
		Natural Gas	Diesel
Max. Unit Capacity	MW	38	38
Min. Unit Capacity	MW	19	20
Min. Unit Capacity (% of max Capacity)	%	51%	51%
Fixed O&M Expense	2018 $/kW-year	41.33	41.33
Variable O&M Expense	2018 $/MWh	3.12	3.12
Heat Rate at 100% Rated Capacity	MMBtu/MWh	8.34	8.08
Annual Required Maintenance Time	Hours per Year	180	180
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	30	30
Ramp Down Rate	MW/minute	30	30
Regulation Minimum Range	MW	19	20
Regulation Maximum Range	MW	38	38
Regulation Ramp Rate	MW/minute	30	30

Exhibit 6-9. Small CCGT (GE LM2500 SAC) Operational Assumptions

Generation Unit Type	Unit	Small CC (GE LM2500 SAC)	
		Natural Gas	Diesel
Max. Unit Capacity	MW	29	28
Min. Unit Capacity	MW	15	14
Min. Unit Capacity (% of max Capacity)	%	51%	51%
Fixed O&M Expense	2018 $/kW-year	42.49	42.49
Variable O&M Expense	2018 $/MWh	3.12	3.12
Heat Rate at 100% Rated Capacity	MMBtu/MWh	8.69	8.46
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	180	180
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	30	30
Ramp Down Rate	MW/minute	30	30
Regulation Minimum Range	MW	15	14
Regulation Maximum Range	MW	29	28
Regulation Ramp Rate	MW/minute	30	30

Exhibit 6-8, Exhibit 6-9 and Exhibit 6-10 present the operational parameters of the GT units (Mobile, GE LM6000 DLE, and GE LM2500 SAC) considered in the IRP, which can cycle in and out of service frequently. The units in Exhibit 6-8 are mobile units and are good candidates for replacement of the existing Frame 5 units (21 MW each).

These GT's typically have a minimum capacity of 50% of the maximum (due to emissions limitations) and can ramp up from minimum to maximum capacity in less than 25 seconds.

Exhibit 6-10. Simple Cycle Mobile Unit

Generation Unit Type	Unit	FT8 MOBILEPAC 25 DLN	
		Natural Gas	Diesel
Max. Unit Capacity	MW	23.2	22.6
Min. Unit Capacity	MW	11.9	11.3
Fixed O&M Expense	2018 $/kW-year	38.62	38.62
Variable O&M Expense	2018 $/MWh	3.12	3.12
Heat Rate at 100% Rated Capacity	MMBtu/MWh	11.12	10.96
Unit Capacity Degradation	%	2.50%	2.50%
Unit Heat Rate Degradation	%	1.50%	1.50%
Annual Required Maintenance Time	Hours per Year	180	180
Unit Forced Outage Rate	%	2%	2%
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	30	30
Ramp Down Rate	MW/minute	30	30
Regulation Minimum Range	MW	11.9	11.3
Regulation Maximum Range	MW	23.8	22.6
Regulation Ramp Rate	MW/minute	30	30

Exhibit 6-11. Simple Cycle Peaker GT (GE LM6000 DLE)
Operational Assumptions

Generation Unit Type	Unit	SC Peaker (GE LM6000 DLE)	
		Natural Gas	Diesel
Max. Unit Capacity	MW	41	39
Min. Unit Capacity	MW	21	19
Min. Unit Capacity (% of Max Capacity)	%	50%	50%
Fixed O&M Expense	2018 $/kW-year	32.85	32.85
Variable O&M Expense	2018 $/MWh	5.29	5.29
Heat Rate at 100% Rated Capacity	MMBtu/MWh	9.83	9.68
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	180	180
Unit Forced Outage Rate	%	0.02	0.02
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	50	50
Ramp Down Rate	MW/minute	50	50
Regulation Minimum Range	MW	21	19
Regulation Maximum Range	MW	41	39
Regulation Ramp Rate	MW/minute	50	50

Exhibit 6-12. Simple Cycle Peaker GT (GE LM2500 SAC)
Operational Assumptions

Generation Unit Type	Unit	SC Peaker (GE LM2500 SAC)	
		Natural Gas	Diesel
Max. Unit Capacity	MW	22	21
Min. Unit Capacity	MW	11	11
Min. Unit Capacity (% of Max Capacity)	%	50%	50%
Fixed O&M Expense	2018 $/kW-year	38.63	38.63
Variable O&M Expense	2018 $/MWh	3.12	3.12
Heat Rate at 100% Rated Capacity	MMBtu/MWh	11.49	11.14
Unit Capacity Degradation	%	2.5%	2.5%
Unit Heat Rate Degradation	%	1.5%	1.5%
Annual Required Maintenance Time	Hours per Year	180	180
Unit Forced Outage Rate	%	0.02	0.02
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	30	30
Ramp Down Rate	MW/minute	30	30
Regulation Minimum Range	MW	11	11
Regulation Maximum Range	MW	22	21
Regulation Ramp Rate	MW/minute	30	30

Source: Siemens

Exhibit 6-11 presents the operational parameters for the RICE technologies, which are very flexible, able to cycle frequently, and have low minimum loading and very fast loading rates.

Exhibit 6-13. Reciprocating Engine Operational Assumptions

Generation Unit Type	Unit	Reciprocating Engine	
		Natural Gas	Diesel
Max. Unit Capacity	MW	16	16
Min. Unit Capacity	MW	2	2
Min. Unit Capacity (% of Max Capacity)	%	10%	10%
Fixed O&M Expense	2018 $/kW-year	28.98	28.98
Variable O&M Expense	2018 $/MWh	10.33	10.33
Heat Rate at 100% Rated Capacity	MMBtu/MWh	8.53	8.89
Unit Capacity Degradation	%	1.0%	1.0%
Unit Heat Rate Degradation	%	0.5%	0.5%
Annual Required Maintenance Time	Hours per Year	360	360
Unit Forced Outage Rate	%	0.02	0.02
Unit Forced Outage Duration	Hours	40	40
Minimum Downtime	Hours	2	2
Minimum Runtime	Hours	2	2
Ramp Up Rate	MW/minute	2.5	2.5
Ramp Down Rate	MW/minute	2.5	2.5
Regulation Minimum Range	MW	5	5
Regulation Maximum Range	MW	16	16
Regulation Ramp Rate	MW/minute	2.5	2.5

Source: Siemens

As discussed, these selections are representative of each particular technology class and do not represent final recommendations of particular equipment or manufacturer. Exact sizing, configuration and performance should be optimized when an actual generation project is planned and implemented. But for planning purposes, these units demonstrate how different representative technologies would fit in the overall dispatch analysis. Output and heat rate degradation are applied as a single adjustment to the “New and Clean” performance to represent annual average performance over the generating unit’s operating life.

Combined Heat and Power (CHP) was also considered as an option and this is discussed in Appendix 4: Demand-Side Resources.

6.3.2.1 Existing Fleet Considerations

In this IRP, no repowering of existing units is considered due to the complications associated with trying to “recycle” aged infrastructure. However, the fuel conversion of San Juan 5&6 was considered as a committed decision and there is the possibility of fuel conversions of the Aguirre CCGT. For the fuel conversion candidates, the capital costs assumptions are presented in Exhibit 6-12.

Exhibit 6-14. Fuel Conversion Projects Capital Costs Assumptions

Dual Fuel Conversion Projects	Capital Costs (thousand 2018$)
Aguirre 1 CCGT Dual Fuel Conversion	25,371
Aguirre 2 CCGT Dual Fuel Conversion	25,371

Source: Siemens

6.3.2.2 Representative Future Generation Resources Capital Costs

Capital costs for the representative future generation resources are key parameters in the IRP models. Siemens developed the capital costs assumptions using the PEACE capital cost estimating module associated with GT Pro software. PEACE uses equipment selection and sizing as determined in GT Pro to estimate equipment and installation costs, including associated costs such as foundations, piping, wiring, buildings, etc. Other components including contractor engineering, commissioning, overhead, escalation, contingency and fees are added to determine the Engineering, Procurement and Construction (EPC) price. Owner's costs for development, permitting and legal/contracting activities, and cost escalation were included in PEACE. Most power projects implemented by private developers on a project non-recourse financing basis, incur total development and financing costs, including Interest during Construction, financing fees, project management, O&M mobilization, startup fuels and consumables, etc. PEACE included 9 percent of EPC for development costs. Also, PEACE includes certain adjustments to labor productivity and labor and materials costs based on project location. However, the program does not include adjustments specific to Puerto Rico costs. Siemens adopted the U.S. Department of Defense Area Cost Factor of 16 percent for Puerto Rico. This adjustment was inserted into PEACE as a user input and it was applied against equipment, material and labor costs to reflect delivery or local purchase and installation of equipment and materials for the project.

PEACE cost estimates are not as accurate as obtaining project specific equipment and construction costs estimates from suppliers and contractors but are suitable for planning purposes and provide a consistent approach across all generation resource options. The PEACE cost estimates also reflect the specific configuration and sizing of options, such as duct firing and Air-Cooled Condensers, which need to be considered when factoring costs based on other projects whose configurations may vary. Exhibit 6-13 shows the estimated all-in capital costs for the selected representative technologies.

Exhibit 6-15. New Generation Resources Capital Costs

Representative New Resource Candidates	Natural Gas Fired		Diesel Fired	
	Capacity (MW)	Capital Costs (2018$/KW)	Capacity (MW)	Capital Costs (2018$/KW)
H Class CCGT (GE S107HA.01)	449	$899	438	$921
F-Class CCGT (GE S107F.04) (Duct Fired)	302	$994	296	$1,017
F-Class CCGT (GE S107F.05) (Duct Fired)	369	$927	361	$948
Medium CCGT (Hitachi H-100) (Duct Fired)	144	$1,250	141	$1,275
Small CCGT (GE LM6000 DLE) (Duct Fired)	66	$1,658	63	$1,729
Small CCGT (GE LM2500+ G4 SAC) (Duct Fired)	38	$1,798	38	$1,812
Small CCGT (GE LM2500 SAC) (Duct Fired)	29	$2,010	28	$2,052
Aero/Small GT Peaker (GE LM6000 DLE)	41	$1,375	39	$1,444
Aero/Small GT Peaker (GE LM2500 SAC)	22	$1,627	21	$1,689
Small CHP (Solar Turbines Mars 100)	9	$2,651	9	$2,639
RICE (Wartsila 18V50DF)	16	$1,612	16	$1,612

Source: Siemens

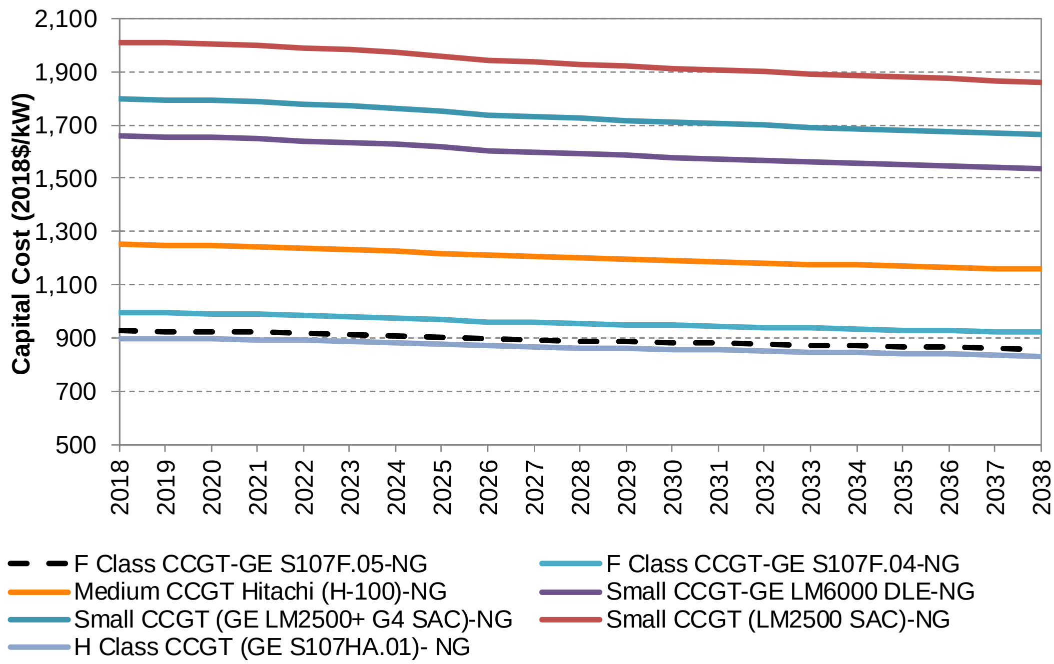
For the replacement of the 21 MW Frame 5 units using the mobile units (FT8 MOBILEPAC 25 DLN) presented earlier, there are capital cost differences whether it is replacing an existing unit or adding another unit on site. This is presented below.

Exhibit 6-16. New Generation Resources Capital Costs

Name	Existing Units	Zone	Capex ($/kW) Existing	Capex ($/kW) Additional
Daguao	2	Carolina	900	1000
Yabucoa	2	Caguas	900	1000
Palo Seco	6	Bayamon	900	1000
Costa Sur	2	Ponce Oe	900	1000
Aguirre	2	Ponce ES	900	1000
Vega Baja	2	Bayamon	900	1000
Jobos	2		900	1000

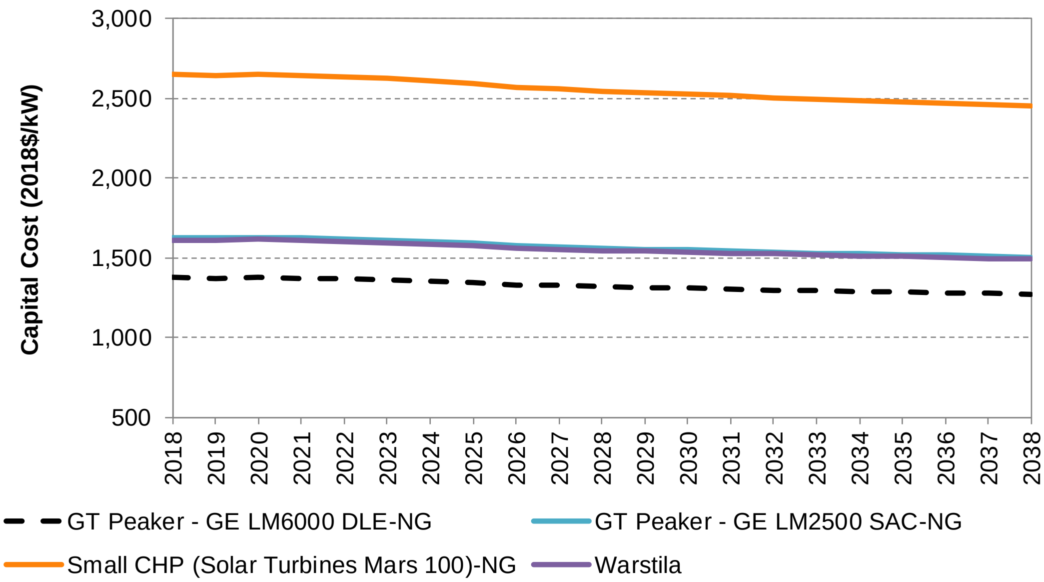
The capital cost curves below are derived based of the 2018 National Renewable Energy Laboratory (NREL) Annual Technology Baseline for the Gas CC/CT based on Annual Energy Outlook 2018. The costs curves can be used to estimate the capital costs for future units considering the deployment dates.

Exhibit 6-17. Capital Cost Curve for Gas CCGT



Source: Siemens, NREL 2018 ATB

Exhibit 6-18. Capital Cost Curve for GT



Source: Siemens, NREL 2018 ATB

6.3.2.3 Considerations on variability of Capital Costs

For the power plants, our estimating methodology was to use Thermoflow software programs, GT Pro and PEACE. GT Pro sizes the main components and prepares a heat balance giving inputs and outputs. PEACE uses algorithms and industry data to prepare a basic cost estimate. These could be described as very early equipment factored cost estimates, but not accounting for specific project sites, except for using ambient temperatures for Puerto Rico.

AACE International Recommended Practice No. 18R-97 is a guideline for process industry cost estimate classification according to the level of development of project definition. The estimates produced in this study would be considered AACE Class 4, with maturity of project deliverables at 1% to 15% (Study or feasibility stage), prepared using equipment factored or parametric models. The AACE range of cost uncertainty for this class of estimate is:

- Low: -15% to -30%
- High: +20% to +50%

Equipment costs as a percentage of total costs tend to be higher for power projects than for other types of process industry projects. Equipment costs are somewhat predictable, though market factors can affect these, as well. Also, it often is possible to find somewhat similar power plants and learn their actual costs.

Based on the above, it is our opinion that the range of uncertainty of the estimates presented here should be in the range of -15% to +30% for the projects with scope as defined in the study.

6.3.3 Future Generation Resources Development Timeline

For addition of new resources, IRPs need to factor development time from the initial RFP to the Commercial Operation Date. Exhibit 6-17 shows the expected development timeframes for the representative technologies. In this exhibit, development includes the activities from RFP and bid evaluation to permitting and financing. The EPC is the actual engineering, procurement and construction to Commercial Operation.

Exhibit 6-19. Development and Construction Durations

Representative New Resource Candidates	Capacity (MW)	Development Duration (Years)	EPC Duration (Years)
H Class CCGT (GE S107HA.01) (Duct Fired)	449	2.5	3.0
F-Class CCGT (GE S107F.04) (Duct Fired)	302	2.5	3.0
F-Class CCGT (GE S107F.05) (Duct Fired)	369	2.5	3.0
Medium CCGT (Hitachi H-100) (Duct Fired)	144	2.5	2.5
Small CCGT (GE LM6000 DLE) (Duct Fired)	66	2.0	2.0
Small CCGT (GE LM2500+ G4 SAC) (Duct Fired)	47.7	2.0	2.0
Small CCGT (GE LM2500 SAC) (Duct Fired)	35	2.0	2.0
Aero/Small GT Peaker (GE LM6000 DLE)	41	1.5	1.5
Aero/Small GT Peaker (GE LM2500 SAC)	22	1.5	1.5
Small CHP (Solar Turbines Mars 100)	9	1.5	1.5
RICE (Wartsila 18V50DF)	16	1.5	1.5

Note: Capacity based on natural gas firing.

6.3.4 Levelized Cost of Energy (LCOE)

A high level LCOE was calculated on all new technologies to form a preliminary view of their respective costs for the IRP.

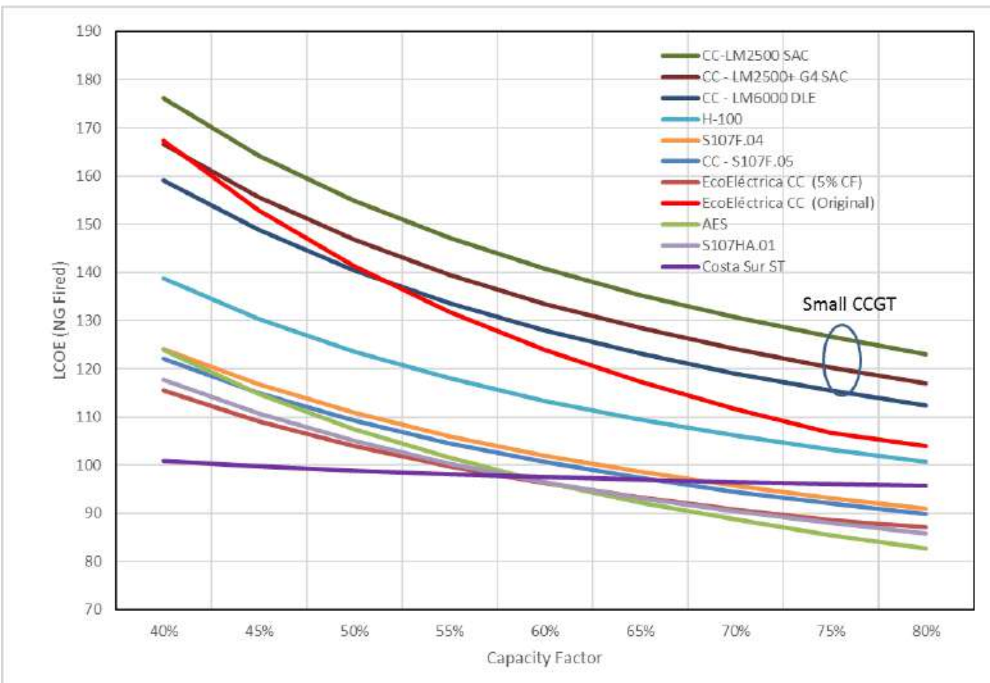
The LCOE was estimated using the heat rate at 100% rated unfired capacity and considering delivered diesel and new natural gas prices (including commodity, liquefaction, and shipping, but not regasification costs) at San Juan to calculate fuel costs. The regasification costs were determined considering a land-based LNG regasification terminal at San Juan with a pipeline to Palo Seco with max daily gas volume of 93.6 MMcf/day to support a total generation capacity of 650 MW. Siemens estimated for the calculations below that this regasification infrastructure adds a fixed cost of $116.5/kW-year to any potential new gas-fired generation resources at San Juan or Palo Seco accounting for fixed operating costs and return on capital at a WACC (weighted average cost of capital) of 8.5 percent and an economic life of 22 years. This same WACC was used to annualize the generation capital considering an asset economic life of 29 years for a large combined cycle plant

and 20 years for the remaining technologies (see Capital Cost Recovery section of this report for additional details).

As a reference, Siemens also calculated the LCOE for Costa Sur 5 & 6 considering the O&M costs plus delivered gas. For AES, Siemens considered the forecasted cost of coal, O&M and capacity payments. For EcoEléctrica, Siemens considered the two fuel components reflected in the PPOA; for energy under 76% dispatch, and for the spot price energy produced above that level it was assumed to be equal to the delivered gas at San Juan. Siemens also factored in the EcoEléctrica O&M costs and capacity payments.

Exhibit 6-18 shows the LCOE of the large and medium CCGT with gas and a comparison with the estimated LCOE of Costa Sur 5&6, EcoEléctrica and AES. Exhibit 6-19 provides the numeric values of this LCOE. As can be observed below, depending on the dispatch (and the fuel price assumptions made), it is possible that EcoEléctrica could be economically retired as well as Costa Sur 5&6, considering that its replacement by a flexible CCGT will reduce the need for energy storage capacity. This result would change for the case where the EcoEléctrica contract is renegotiated, and the capacity payments are reduced.

Exhibit 6-20. Large and Medium CCGT with Gas, Costa Sur 5&6, EcoEléctrica and AES



Source: Siemens

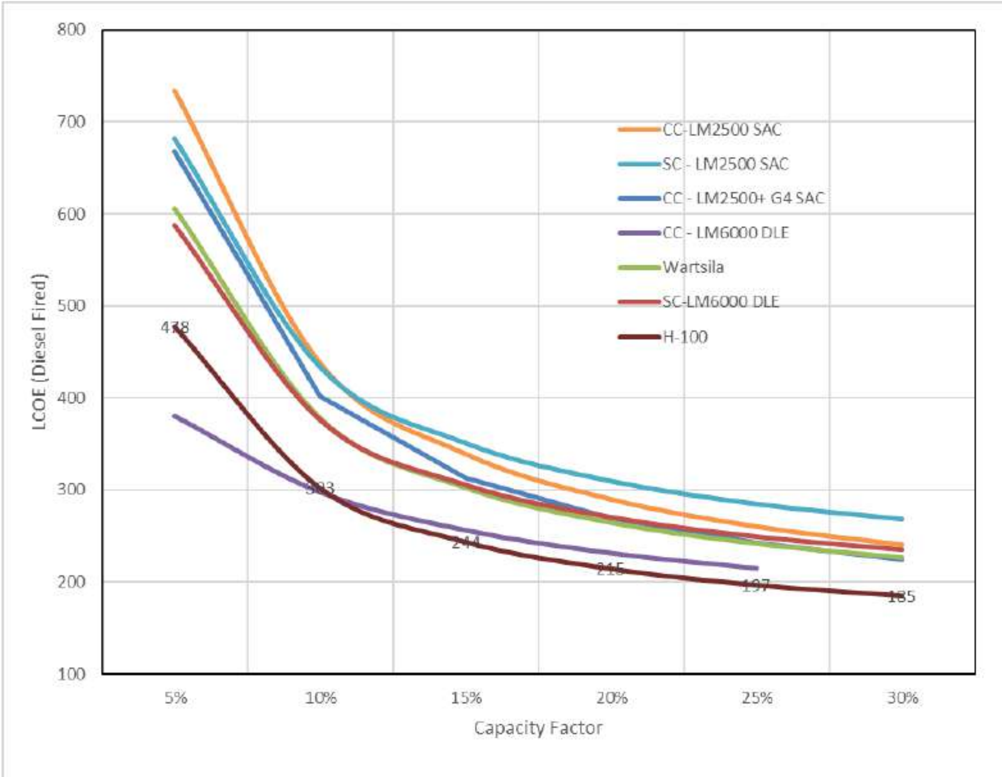
Exhibit 6-21. LCOE for Large and Medium Combined Cycle units

Case Description	H Class CCGT		F Class CCGT		F Class CCGT		Medium CCGT	
Manufacturer	GE		GE		GE		MHPS	
Model	S107HA.01		CC - S107F.05		S107F.04		H-100	
Type	CC 1x1		CC 1x1		CC 1x1		CC 1x1	
Capacity MW	449	438	369	361	302	296	144	141
Fuel	NG	Diesel	NG	Diesel	NG	Diese	NG	Diesel
Capacity Factor	**LCOE (2018$/MWh)**							
5%	565	360	574	373	589	388	674	478
10%	309	235	316	246	323	253	368	303
15%	224	193	230	203	235	208	266	244
20%	182	173	187	182	191	186	215	215
25%	156	160	161	169	164	172	185	197
30%	139	152	144	161	146	163	164	185
35%	127	146	131	154	134	157	150	177
40%	118	141	122	150	124	152	139	171
45%	111	138	115	146	117	148	130	166
50%	105	135	109	144	111	145	124	162
55%	100	133	105	141	106	143	118	159
60%	96	131	101	139	102	141	113	156
65%	93	129	97	138	99	139	109	154
70%	90	128	94	136	96	138	106	152
75%	88	127	92	135	93	136	103	150
80%	86	126	90	134	91	135	101	149
85%	84	125	88	133	89	134	98	148
90%	82	124	86	132	87	133	96	146

Source: Siemens

With respect of the small CCGT units, GT and the Wärtsilä RICE, Exhibit 6-20 below shows the LCOE cost converge near the expected capacity factor ranges, with perhaps the LM2500 being the least competitive. The LCOE is presented considering Diesel (LFO) as the likely fuel for these units. Exhibit 6-21 show the numeric values for the LCOE for the small CCGT units and Exhibit 6-22 for the CHP option. Siemens further notes in this exhibit that for applications where large amount of power are required, the H-100 Combined Cycle and the LM6000 Combined Cycle are competitive even at very small capacity factors.

Exhibit 6-22. Small CCGT, Peakers (GT) and RICE with Diesel



Source: Siemens

Exhibit 6-23. LCOE for Small Combined Cycle units and GT Aero Peakers

Case Description	Aero or Small CCGT		Aero or Small CCGT		Aero or Small CCGT		Aero SC/ Peaker		Aero SC/ Peaker	
Manufacturer	GE		GE		GE		GE		GE	
Model	CC - LM6000 DLE		CC - LM2500+ G4 SAC		CC-LM2500 SAC		SC-LM6000 DLE		SC - LM2500 SAC	
Type	CC 1x1		CC 1x1		CC 1x1		SC		SC	
	x`	63	38	38	29	28	41	39	22	21
Fuel	NG	Diesel	NG	Diesel	NG	Diesel	NG	Diesel	NG	Diesel
Capacity Factor	**LCOE (2018$/MWh)**									
5%	814	631	861	667	918	734	754	588	838	682
10%	440	381	464	402	494	438	417	376	465	434
15%	315	298	332	313	353	340	305	306	340	351
20%	253	256	266	269	282	290	249	270	278	310
25%	215	231	226	242	240	261	215	249	241	285
30%	190	214	200	225	211	241	193	235	216	269
35%	173	202	181	212	191	227	177	225	198	257
40%	159	194	167	202	176	216	165	217	185	248
45%	149	187	156	195	164	208	156	211	175	241
50%	140	181	147	189	155	201	148	207	166	236
55%	134	177	140	184	147	196	142	203	159	231
60%	128	173	134	180	141	192	137	200	154	228
65%	123	170	128	177	135	188	133	197	149	224
70%	119	167	124	174	131	184	129	195	145	222
75%	115	164	120	171	127	182	126	193	141	219
80%	112	162	117	169	123	179	123	191	138	217
85%	110	160	114	167	120	177	121	189	135	215
90%	107	159	111	166	117	175	118	188	133	214

Source: Siemens

Exhibit 6-24. LCOE for CHP and RICE Units

Case Description	CHP		CHP (56% Heat Rate)		RICE
Manufacturer	Solar Turbines		Solar Turbines		Wartsila
Model	Mars 100		Mars 100		Wartsila 18V50DF
Type	Cogen -- LP steam		Cogen -- LP steam		
Capacity MW	9	9	9	9	16
Fuel	NG	Diesel	NG	Diesel	Diesel
Capacity	**LCOE (2018$/MWh)**				
5%	1124	962	1076	867	606
10%	614	587	566	491	378
15%	444	461	396	366	302
20%	359	399	311	304	264
25%	308	361	260	266	242
30%	274	336	226	241	226
35%	250	318	202	223	216
40%	232	305	183	210	207
45%	217	294	169	199	201
50%	206	286	158	191	196
55%	197	279	149	184	192
60%	189	274	141	178	188
65%	183	269	134	174	185
70%	177	265	129	169	183
75%	172	261	124	166	181
80%	168	258	120	163	179
85%	164	255	116	160	177
90%	161	253	113	158	176

Source: Siemens

6.4 Solar Photovoltaic (PV) Projects

The IRP assumes utility scale solar for new builds of renewable resources. The cost estimates for utility scale solar PV projects are developed through the following steps: 1) establish baseline solar PV operating and overnight capital costs estimate; 2) evaluate interconnection and land costs specific to Puerto Rico; 3) assess construction and financing costs reflecting Puerto Rico specific assumptions; and 4) calculate Levelized Cost of Energy (LCOE) for solar PV in Puerto Rico.

6.4.1 Baseline Operating and Overnight Capital Costs

For step 1, the IRP assumes overnight capital costs and operating costs for utility-scale PV systems consistent with the recently published 2018 Annual Technology Baseline (ATB) by National Renewable Energy Laboratory (NREL) as shown in Exhibit 6-23. The PV system is representative of one-axis tracking systems with performance and pricing characteristics; this cost is somewhat higher than the cost of fixed tilt normally used in Puerto Rico, but it was maintained considering that in the territory additional costs may be incurred for hardening. The assumptions below do not account for a

1.3 DC-to-AC ratio, otherwise known as inverter loading ratio that is included when calculating the LCOE.

Exhibit 6-25. U.S. Utility Scale Solar PV Costs Assumptions

NREL 2018 Annual Technology Baseline (ATB) Mid Case			NREL 2018 Annual Technology Baseline (ATB) Low Case		
Year	PV Overnight Capital Costs $2018/KWdc	Fixed Operating Costs $2018/kW-year (dc)	Year	PV Overnight Capital Costs $2018/KWdc	Fixed Operating Costs $2018/kW-year (dc)
2018	1,087	9.52	2018	960	8.51
2019	1,046	9.11	2019	912	8.04
2020	984	8.37	2020	870	7.45
2021	933	7.80	2021	833	7.00
2022	923	7.71	2022	810	6.81
2023	912	7.63	2023	786	6.62
2024	902	7.54	2024	763	6.43
2025	891	7.46	2025	739	6.24
2026	880	7.38	2026	715	6.05
2027	870	7.29	2027	692	5.87
2028	859	7.21	2028	668	5.68
2029	849	7.12	2029	645	5.49
2030	838	7.04	2030	621	5.30
2031	831	6.98	2031	611	5.22
2032	824	6.92	2032	600	5.13
2033	817	6.86	2033	590	5.05
2034	809	6.81	2034	582	4.98
2035	802	6.75	2035	565	4.85
2036	795	6.69	2036	552	4.74
2037	788	6.63	2037	538	4.64
2038	780	6.57	2038	525	4.53
2039	773	6.52	2039	512	4.43

Source: NREL 2018 ATB, converted to $2018. (https://atb.nrel.gov/electricity/data.html)

6.4.2 Interconnection Costs

The NREL benchmark includes the transformation to transmission voltage level (e.g. 115 kV) and a cost of $0.03/Wdc[34] for interconnection costs to the point of interconnection (POI) and a cost of $263,000 for the interconnecting lines (Gen-Ties) to the POI (based on a 30 MW plant). In the case of PREPA, these costs can change significantly, thus Siemens added the PREPA specific cost to its estimate and subtracted the corresponding NREL cost element. Exhibit 6-24 shows the interconnection costs assumed for a solar PV project that includes the expansion of an existing substation with one new bay for the solar PV project, the expansion of the control house, and 1 mile of interconnecting line. All unit costs shown were provided by PREPA.

Exhibit 6-26. Interconnection Costs

Interconnection Costs	Unit	Value	Unit Price $/unit	Capital ($ 000)
Interconnecting Line (Gen-Tie)	Miles	1	1,500,000	1,500
Right of Way Costs (115 kV 50 ft wide)	m2	24,521	3	74
New Bay for Interconnection	Each	1	2,400,000	2,400
Control House Extension	Each	1	300,000	300
Total Interconnection Cost				4,274
Cost already included in NREL				(1,433)
Total Adjusted Interconnection Cost				**2,840**

Note: The NREL interconnection costs are subject to update upon receiving response from the NREL

[34] The NREL interconnection costs are subject to update upon receiving response from the NREL

6.4.3 Land Costs

PV facilities require large stretches of land. NREL on its report "Land-Use Requirements for Solar Power Plants in the United States" indicates that for large projects (greater than 20 MW) the land use is approximately 7.5 acres per MWac for fixed tilt systems and approximately and 8.3 acres per MWac for one-axis tilt systems. These values are in the mid-range of project values ranging from 9 acres per MWac to 5 acres per MWac, based on Siemens projects experience.

Using NREL values, a 30 MW[35] project would require an area of 225 acres or 910,543 m^2. Using the land cost provided by PREPA the table below shows Siemens estimation of costs for a 30 MW project. Note that in this table, Siemens is subtracting the costs already included in NREL benchmark ($0.03/Wdc).

Exhibit 6-27. Land Costs

Land Costs (30 MW Solar)	Unit	Value	Unit Price $/unit	Capital ($ 000)
Area for PV Project	m2	910,543	3	2,732
Cost already included in NREL				1,170
Total land cost				**1,562**

6.4.4 Weighted Average Cost of Capital (WACC)

A WACC of 8.5% was used in this analysis as presented in the section on Capital Recovery Factor at the beginning of this Part 6.

6.4.5 Investment Tax Credit (ITC)

The solar Investment Tax Credit (ITC) is one of the most important federal policy mechanisms to support the deployment of solar energy in the United States. Consistent with the current policy, the IRP assumes the following: solar facilities that commence construction prior to January 1, 2020 will qualify for the full amount of the ITC (i.e., 30 percent); solar facilities that commence construction during 2020, the amount of the ITC will be reduced from 30 percent to 26 percent; solar facilities that commence construction during 2021, the amount of the ITC will be reduced from 26 percent to 22 percent; and solar facilities that commence construction in 2022 or thereafter, the amount of the ITC will drop to 10 percent.

6.4.6 Project Development and Construction Time

Based on discussions with PREPA, the IRP assumes an accelerated timeline for solar projects, assuming 12 months for the development period (request for proposal, bid evaluation, permitting, and financing) and 12 months for construction.

This time line assumes fast track permitting, proper submittal of project design for evaluation by PREPA (particularly for mathematical model evaluation, and control, protection and telecommunications design), as well as securing the land for the interconnection line and any additional land acquisition required for interconnection at PREPA's facilities that will be secured by

[35] 30 MW was selected as a representative size of a utility scale project.

project company. Those projects that require new-build PREPA interconnection facilities (sectionalizer or transmission centers) could require longer development and construction times.

Additionally, there are limits on the amount of annual installations that can effectively be carried out in parallel. This changes as a function of the Scenarios discussed earlier and are as presented below.

Exhibit 6-28: Solar PV and BESS Annual Installation Constraints for Core Scenarios 1, 4, 5, and 6

	2019	2020	2021	2022-2038
Solar PV Annual Installation Limit (MW)	0	300	300	600
BESS Annual Installation Limit (MW)	60-180	300	300	600

Exhibit 6-29: Solar PV and BESS Annual Installation Constraints for Sensitivity 1 (low cost of renewable)

	2019	2020	2021	2022-2038
Solar PV Annual Installation Limit (MW)	0	300	1200	1200
BESS Annual Installation Limit (MW)	60-180	300	1200	1200

For modeling the ESM Scenario, the following limits were considered:

Exhibit 6-30: Solar PV and BESS Annual Installation Constraints for ESM Scenario

Year of Completion	2019	2020	2021	2022	2023	2024
Photovoltaic Resources (PV)						
Annual Increment (MW)	-	-	240	480	480	300
Cumulative Total (MW)			240	720	1200	1500
Battery Energy Storage Systems (BESS)						
Annual Increment (MW)	20	100	160	160	160	150
Cumulative Total (MW)	20	120	280	440	600	750

6.4.7 Levelized Cost of Energy (LCOE)

For the IRP modeling, the levelized cost of energy (LCOE) is calculated as the net present value of the unit-cost of energy over the lifetime of the solar PV asset. The LCOE is then used as a proxy for the average price that the solar PV project could break even over its lifetime. Exhibit 6-30 shows the LCOE of solar PV under Mid case and Low case. Exhibit 6-31 shows the other assumptions used in deriving the LCOE. Exhibit 6-32 shows graphically the cost trend, and Exhibit 6-33 and Exhibit 6-34 show the LCOE calculation for the base case and low case separately.

Exhibit 6-31. Levelized Cost of Energy (LCOE) of Solar PV

Levelized Cost of Energy in Puerto Rico		
Commercial On Line (COD) Year	Mid Case Solar PV 2018$/MWh	Low Case Solar PV 2018$MWh
2018	69	62
2019	67	59
2020	63	56
2021	64	58
2022	67	60
2023	78	68
2024	77	67
2025	76	65
2026	76	63
2027	75	61
2028	74	59
2029	73	57
2030	72	55
2031	72	55
2032	71	54
2033	71	53
2034	70	52
2035	70	51
2036	69	50
2037	68	49
2038	68	48

Exhibit 6-32. Levelized Cost of Energy (LCOE) Assumptions

Item	Unit	Assumption
DC / AC Conversion	X	1.3
Size	MW	30
Solar Capacity Factor	%	22%
Wind Capacity Factor	%	25%
Puerto Rico Solar Overnight Cost Adder	%	16%
Solar Construction Finance Factor	%	101.5%
Wind Construction Finance Factor	%	102.5%
Small Scale Adder	%	0%
Solar PV /Wind Capital Recovery Period	year	30
Battery Storage Capital Recovery Period	year	20
$2016 to $2018 Conversion	X	1.035

The 16% Puerto Rico Overnight Cost Adder factor accounts for island cost premiums relative to "typical" mainland US costs and corresponds to the U.S. Department of Defense Area Cost Factor for Puerto Rico

Exhibit 6-33. Photovoltaic Levelized Cost of Energy (LCOE) 2018$/MWh

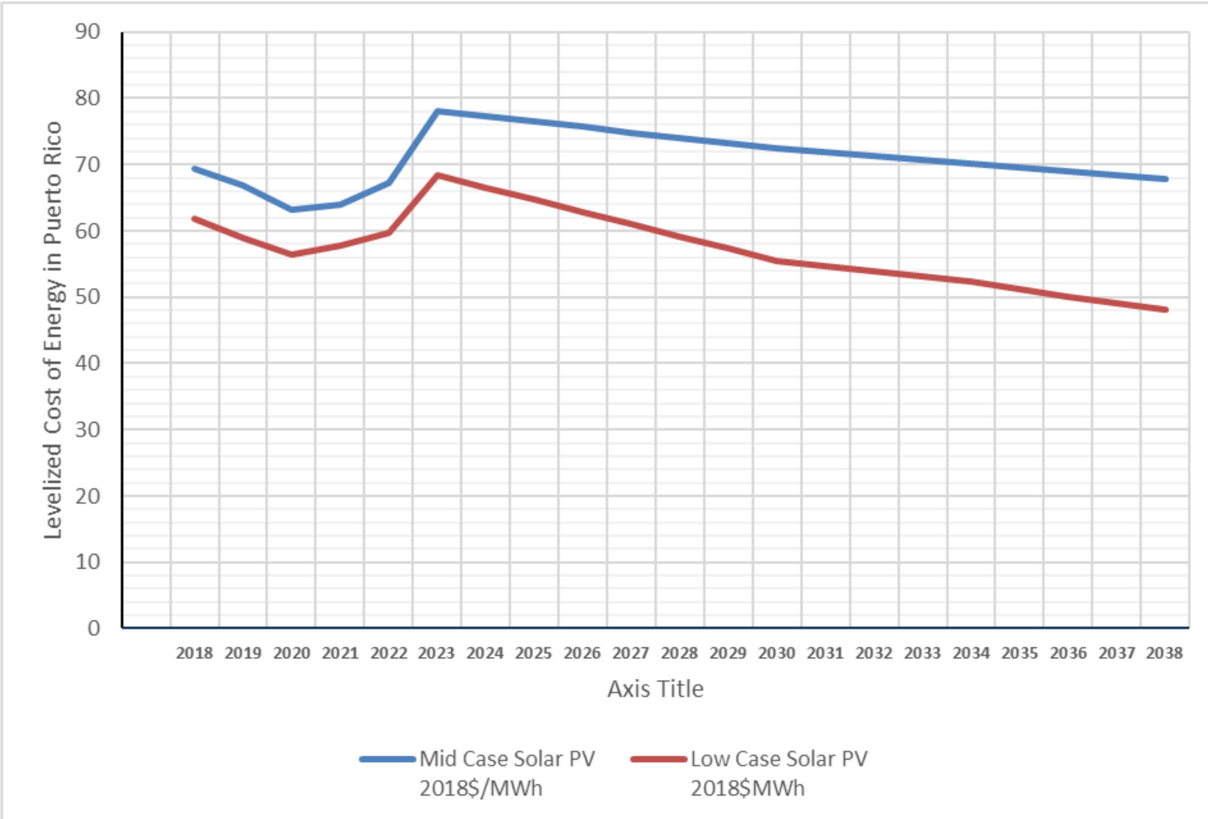


Exhibit 6-34. Levelized Cost of Energy (LCOE) of Solar PV – Base Case

Commercial on line year		2019	2020	2021	2022	2023	2024	2025	*2030*	*2035*	*2038*
Construction Start Year		2018	2019	2020	2021	2022	2023	2024	*2029*	*2034*	*2037*
Capital and Operating Costs											
Overnight Cost, US National, 100 MW	$2018/Wdc	1.05	0.98	0.93	0.92	0.91	0.90	0.89	0.84	0.80	0.78
AC/DC Conversion	X	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Puerto Rico Adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Overnight Cost, Puerto Rico, 100 MW	$2018/Wac	1.58	1.48	1.41	1.39	1.38	1.36	1.34	1.26	1.21	1.18
IDC Cost Adder	%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
All-In Cost, Puerto Rico, 100 MW, $/Wac	$2018/Wac	1.60	1.51	1.43	1.41	1.40	1.38	1.36	1.28	1.23	1.19
Small Scale Adder (30 MW)	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Base Cost, Puerto Rico, 30 MW	$2018/Wac	**1.60**	**1.51**	**1.43**	**1.41**	**1.40**	**1.38**	**1.36**	**1.28**	**1.23**	**1.19**
Fixed O&M	$2018/kW-yr	11.85	10.88	10.14	10.03	9.92	9.81	9.70	9.15	8.77	8.55
30 MW Solar PV Project Parameters											
Capacity	MW	30	30	30	30	30	30	30	30	30	30
Capacity Factor	%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%
Energy Produced	MWh	57,816	57,816	57,816	57,816	57,816	57,816	57,816	57,816	57,816	57,816
Base Capital PV System	$2018 thousand	48,033	45,207	42,853	42,369	41,885	41,401	40,917	38,498	36,835	35,837
Interconnection Costs	$2018 thousand	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840
Land Costs	$2018 thousand	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562
Total PV System Capital Costs	$2018 thousand	52,435	49,609	47,255	46,771	46,287	45,803	45,319	42,900	41,237	40,239
ITC	%	30%	30%	26%	22%	10%	10%	10%	10%	10%	10%
Income Tax	%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%
Capital Recovery Factor	%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%
Project Financing Factor	%	71%	71%	76%	81%	97%	97%	97%	97%	97%	97%
Construction Financing Factor	%	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Annualized PV Capital Costs	$2018 thousand	**3,510**	**3,321**	**3,392**	**3,584**	**4,220**	**4,176**	**4,132**	**3,911**	**3,759**	**3,668**
Fixed O&M	$2018 thousand	355	327	304	301	297	294	291	274	263	256
Total Base PV System Cost	$2018 thousand	**3,866**	**3,648**	**3,697**	**3,885**	**4,517**	**4,470**	**4,422**	**4,186**	**4,023**	**3,925**
Levelized Cost of Energy (PV Base)	$2018/MWh	**67**	**63**	**64**	**67**	**78**	**77**	**76**	**72**	**70**	**68**

Exhibit 6-35. Levelized Cost of Energy (LCOE) of Solar PV – Low Case]

Commercial on line year		2019	2020	2021	2022	2023	2024	2025	*2030*	*2035*	*2038*
Construction Start Year		2018	2019	2020	2021	2022	2023	2024	*2029*	*2034*	*2037*
Capital and Operating Costs											
Overnight Cost, US National, 100 MW	$2018/Wdc	0.91	0.87	0.83	0.81	0.79	0.76	0.74	0.62	0.56	0.53
AC/DC Conversion	X	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Puerto Rico Adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Overnight Cost, Puerto Rico, 100 MW	$2018/Wac	1.38	1.31	1.26	1.22	1.19	1.15	1.11	0.94	0.85	0.79
IDC Cost Adder	%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
All-In Cost, Puerto Rico, 100 MW, $/Wac	$2018/Wac	1.40	1.33	1.28	1.24	1.20	1.17	1.13	0.95	0.86	0.80
Small Scale Adder (30 MW)	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Base Cost, Puerto Rico, 30 MW	$2018/Wac	**1.40**	**1.33**	**1.28**	**1.24**	**1.20**	**1.17**	**1.13**	**0.95**	**0.86**	**0.80**
Fixed O&M	$2018/kW-yr	10.45	9.69	9.10	8.85	8.61	8.36	8.12	6.89	6.30	5.89
30 MW Solar PV Project Parameters											
Capacity	MW	30	30	30	30	30	30	30	30	30	30
Capacity Factor	%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%
Energy Produced	MWh	57,816	57,816	57,816	57,816	57,816	57,816	57,816	57,816	57,816	57,816
Base Capital PV System	$2018 thousand	41,885	39,933	38,273	37,189	36,105	35,021	33,937	28,517	25,935	24,116
Interconnection Costs	$2018 thousand	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840
Land Costs	$2018 thousand	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562
Total PV System Capital Costs	$2018 thousand	46,287	44,335	42,675	41,591	40,507	39,423	38,339	32,919	30,337	28,518
ITC	%	30%	30%	26%	22%	10%	10%	10%	10%	10%	10%
Income Tax	%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%
Capital Recovery Factor	%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%
Project Financing Factor	%	71%	71%	76%	81%	97%	97%	97%	97%	97%	97%
Construction Financing Factor	%	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Annualized PV Capital Costs	$2018 thousand	**3,099**	**2,968**	**3,064**	**3,187**	**3,693**	**3,594**	**3,495**	**3,001**	**2,766**	**2,600**
Fixed O&M	$2018 thousand	314	291	273	266	258	251	243	207	189	177
Total Base PV System Cost	$2018 thousand	**3,412**	**3,259**	**3,337**	**3,453**	**3,951**	**3,845**	**3,739**	**3,208**	**2,955**	**2,777**
Levelized Cost of Energy (PV Base)	$2018/MWh	**59**	**56**	**58**	**60**	**68**	**67**	**65**	**55**	**51**	**48**

6.4.8 Minimum Technical Requirements (MTR)

Renewable energy projects in Puerto Rico must comply with minimum technical requirements (MTR) to allow for their integration into the island's grid. In addition to the frequency ride through, voltage ride through and voltage regulation requirements, the MTR require the renewable generation to contribute to frequency response and most importantly limits its ramps to 10% of the project's Contractual Capacity per minute for both increase and decreases in production. This last requirement is subject to the limitations of the Battery Energy Storage System (BESS) with a Nominal Storage Capacity (NSC) equal to 30% of the Contractual Capacity and an Effective Storage Capacity (ESC) of 45% of the Contractual Capacity, deliverable for up to 1 minute. The ramp control poses the highest demands of active power and energy on the BESS and defines its size and cost.

The minimum energy requirements for ramp control could be assessed considering a situation where a project is delivering 100% of its capacity and due to a rapid cloud cover the output drops to practically zero. In this case the requirement becomes the Effective Storage Capacity (ESC) for one minute and then the Nominal Storage Capacity (NSC) for the balance of the time until the output is taken down to zero. However, from a practical perspective, an energy output equal to 10 min x 30% Project Capacity, would cover this requirement and leave some margin.

However, in the IRP Siemens expects that important levels of BESS will be installed in the system with the dual purpose of providing frequency regulation and shifting energy from day peak to night peak. Thus, modelling the frequency regulation and ramp rate control related MTRs in the IRP including the requirement for storage may result in inefficiencies particularly considering that: a) the investments in the balance of system (BOS) that includes the Power Conversion System (PCS) are similar regardless the energy storage is 10 minutes or 4 hours, making the second much more competitive and b) linking the renewable additions with a BESS may result in investments beyond the actual requirements for the system. Therefore, in the context of this IRP, the solar PV projects and the storage projects are considered separately with the consideration that, during the Request for Proposals (RFPs) to be issued during the implementation phase for solar PV projects, the required component of storage for its integration shall be added, with the flexibility for bidders to bid on one or both components.

PREPA should not commission neither allow the interconnection of PV solar or wind projects to the grid until the assessed need for energy storage is also in place and interconnected in full compliance with the energy storage technical requirements. It is also very important to emphasize that the solar PV projects shall still comply with the MTRs related with frequency ride through, voltage ride through, reactive power capability and voltage regulation in addition to their full compliance with the frequency regulation and frequency response requirements to be met by either separate or integrated energy storage. This approach is expected to foster competition and innovation while at the same time ensuring that the required regulation and energy shifting will be available for the PV integration before its interconnection.

6.5 Battery Storage

The goal of moving toward a low carbon future is leading to a proliferation of utility-scale solar PV and wind generation, and growing levels of distributed energy resources (DER) behind the meter. These developments are challenging the historical centralized paradigm for how a utility should design, build and manage an electricity system. Without the proper foundation of utility-integrated energy storage and software controls, renewable energy resources could face technical and operational challenges and curtailment of highly valued carbon-free electricity could be required in order for the utility to maintain system stability and reliability.

Energy storage technologies can prove valuable to utilities in managing such change as these technologies have the ability to decouple energy supply and demand, and thus provide a valuable resource to system operators. Energy storage could serve as generation or load and to produce or absorb both real and reactive power. Currently, Li-ion batteries are the most relevant battery technology with wide applications in power electronics, electric vehicles (EVs), and stationary storage (grid-scale).

6.5.1 Installed Costs and Applications

While energy storage costs and performance data are global in nature, the results presented here are most representative of the current U.S. energy storage market. The key individual costs making up the total energy storage system costs are detailed below:

Capital costs: The capital costs are for the entirety of the Battery Energy Storage System (BESS), which comprises the battery cell, the Power Conversion System (PCS) costs, and the related EPC costs. The battery energy storage system costs include the storage module (SM) and the balance of system (BOS) costs.

Augmentation costs: Augmentation costs represent the additional BESS equipment needed to maintain the usable energy capability to cycle the unit according to the usage profile in the particular use case, for the life of the system. Additional equipment is required in the following circumstances: (1) if the particular unit charges or discharges to a level less than its rated energy capacity (kWh) per cycle; (2) if the battery chemistry does not have the cycle-life needed to support the entire operating life of the use case; or (3) if the energy rating (kWh) of the battery chemistry degrades due to usage and can no longer support the intended application. This time-series of varying costs is then converted into a level charge over the life of the system to provide greater clarity for project developers.

Operating costs: These include the O&M costs, charging costs, and costs of extended warranties for the major equipment.

Other costs: These include financing costs (debt service payments), taxes paid, costs of meeting local and regional regulatory requirements, and warranty costs.

The costs of energy storage systems are based on specific selected grid applications and the power rating and usage duration assumptions are given below:

Peaker replacement: Large-scale energy storage system designed to replace peaking gas turbine facilities; brought online quickly to meet rapidly increasing demand for power at peak; can be quickly taken offline as power demand diminishes.

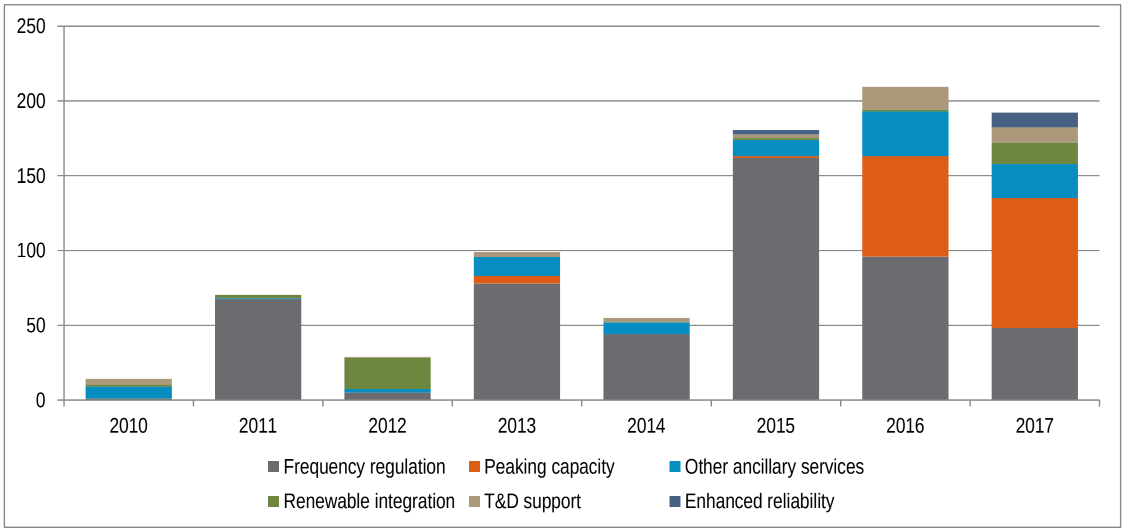
Distribution: Energy storage system designed to defer distribution upgrades, typically placed at substations or distribution feeder controlled by utilities to provide flexible peaking capacity, while also mitigating stability problems.

Microgrid: Energy storage system designed to support small power systems that can “island” or otherwise disconnect from the broader power grid (e.g., military bases, universities, etc.), to provide energy shifting, ramping support to enhance system stability, and increase reliability of service (emphasis is on short-term power output vs. load shifting, etc.).

While the majority of installed capacity provides frequency regulation, recent projects have targeted alternative applications including peaking capacity, renewable integration, and peak shaving. Exhibit

6-35 shows the primary application for installed storage capacity in recent history. The primary application is defined as the service that motivated the project, generally the highest-value or most profitable service. The category "other ancillary services" includes voltage support, black start, and operating reserves; and the category "renewable integration" is primarily energy shifting.

Exhibit 6-36. U.S Installed Capacity (MW) by Primary Application



Source: Siemens, IHS Markit

6.5.2 Future Cost Trends

Battery costs ($/kWh) can be lowered either by reducing the cost of the battery modules and balance of system (reducing $) or by improving the battery performances (increasing kWh) or by a combination of the two approaches.

Cost of batteries can be further reduced relative to where they are today by focusing on the battery modules and battery parts. However, it should be noted that extracting further cost reductions for the balance of system is going to prove increasingly difficult as the battery parts and materials become increasingly commoditized. The following options can be pursued to reduce battery cost:

- Using cheaper materials to build battery parts e.g. electrodes, electrolytes, separators, etc.
- Improving the supply chain and making the manufacturing processes for battery modules more cost effective
- Increasing the scale of manufacturing to spread the capital and fixed O&M costs over a very large number of modules produced

Battery performance can be further improved relative to where it is today, and this needs to be accomplished while keeping the costs comparable to today's technologies. The following avenues are being pursued to improve battery performance:

- Technological improvements, advances or breakthroughs, that lead to better performance, (e.g., cycle life, higher safety, more environmentally friendly, higher energy density, increasing voltage, and higher power density);

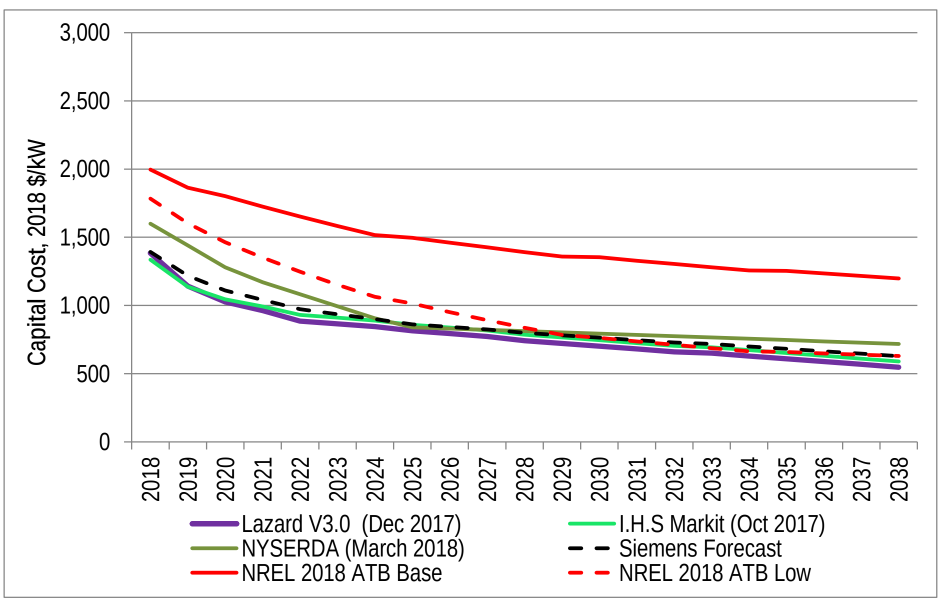
- Using better, more stable materials to build battery parts, (e.g., electrodes, electrolytes, and separators) that are able to deliver the better performance listed above;
- Using more effective chemistries, formulations, or crystal structures that overcome some of the limitations of today's technologies; and
- Using more stable solid electrolytes that enable higher voltages, reduce flammability, and make pure metal (e.g., lithium) anodes safer.

6.5.3 Li-ion Battery System Price Forecast

Li-ion batteries are, and are expected to remain, the mainstream technology for electrochemical energy storage. The support this technology has gathered at both the policy and industrial level is strong enough to keep it going for years to come. Multi-billion-dollar investments are already in place and a quiet arms race is in place to take the place of established Japanese and Korean battery companies, with the biggest threat being from China. Though medium-term shortages of raw materials such as cobalt may increase this portion of the cost somewhat, the larger declines driven by increased scale of production and intense worldwide competition, is likely to drive down the prices overall. As both the stationary energy storage and electric vehicle volumes begin to increase, new low-cost manufacturing facilities will continue to be built, particularly in China, which is expected to help prices continue to fall, albeit at a more temperate rate (~ 10–20% per year) through 2022. Beyond 2022, as economies of scale are maximized and technology improvements slow, battery prices are expected to approach the bottom and stabilize, limiting the decline to less than 5% a year.

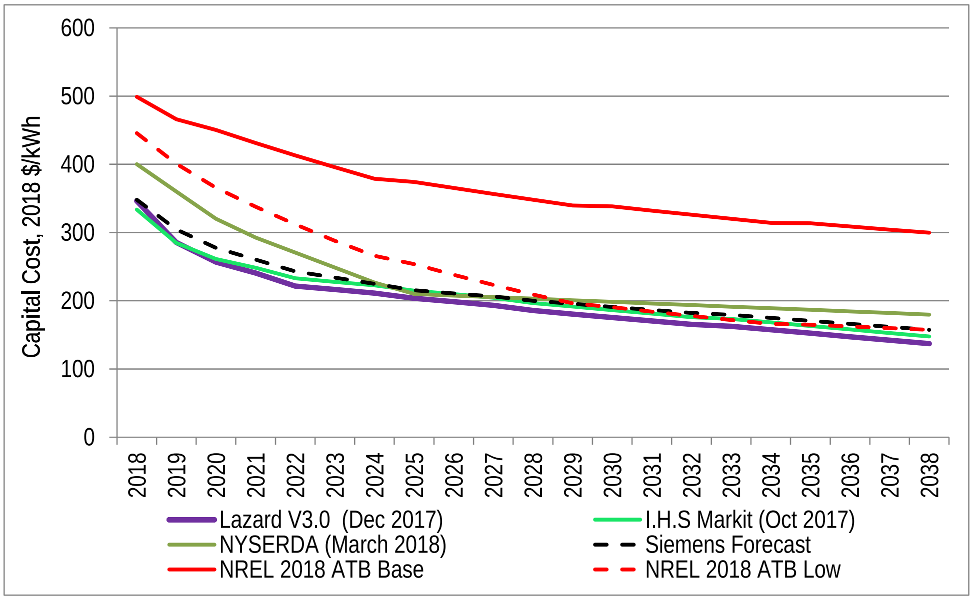
The Exhibits below represent Siemens view of 4-hour 1 MW Li-Ion battery system price forecasts, in $/kW and $/kWh, respectively, in comparison with multiple other forecasts.

Exhibit 6-37-. 4-hour Li-ion Battery System Capital Cost Forecasts



Source: Siemens, IHS, Lazard, NYSERDA, NREL

Exhibit 6-38. 4-hour Li-ion Battery System Capital Cost Forecasts



Note: The capital cost ($/kW) is converted to LCOE ($/kWh) based on the 4-hour cycle of the battery storage.

Source: Siemens, IHS, Lazard, NYSERDA, NREL

Exhibit 6-38 and Exhibit 6-39 present the capital and operating costs assumptions of 2-hour, 4-hour and 6-hour storage in the base case and low case, respectively.

Exhibit 6-39. Li-Ion Battery System Capital Cost and Operating Cost Assumptions – Base Case

Construction Year	All-in Capital Costs			Operating Costs	
	4-hour Li-ion Battery Storage 2018$/KW	2-hour Li-ion Battery Storage 2018$/KW	6-hour Li-ion Battery Storage 2018$/KW	Fixed Operating Costs 2018$/kW-year	Variable Operating Costs 2018$/MWh
2018	1,392	832	1,953	9.09	2.67
2019	1,218	734	1,703	8.96	2.60
2020	1,110	674	1,546	8.95	2.58
2021	1,041	635	1,447	8.81	2.51
2022	972	596	1,349	8.67	2.43
2023	936	576	1,296	8.54	2.36
2024	899	556	1,243	8.41	2.29
2025	861	534	1,188	8.40	2.28
2026	843	523	1,163	8.26	2.20
2027	825	512	1,138	8.12	2.13
2028	800	496	1,104	7.99	2.06
2029	782	485	1,079	7.86	1.99
2030	764	474	1,054	7.85	1.97
2031	746	462	1,031	7.71	1.90
2032	728	450	1,007	7.57	1.82
2033	717	443	992	7.44	1.75
2034	700	431	969	7.31	1.69
2035	682	419	945	7.30	1.67
2036	664	407	922	7.19	1.64
2037	647	395	898	7.08	1.62
2038	629	383	875	6.97	1.59

Source: Siemens, NREL

Exhibit 6-40. Li-Ion Battery System Capital Cost and Operating Cost Assumptions – Low Case

Construction Year	All-in Capital Costs			Operating Costs	
	4-hour Li-ion Battery Storage 2018$/KW	2-hour Li-ion Battery Storage 2018$/KW	6-hour Li-ion Battery Storage 2018$/KW	Fixed Operating Costs 2018$/kW-year	Variable Operating Costs 2018$/MWh
2018	1,236	756	1,716	8.52	2.55
2019	1,047	651	1,443	8.22	2.45
2020	931	588	1,275	8.15	2.42
2021	857	549	1,165	7.81	2.31
2022	779	506	1,053	7.49	2.19
2023	743	488	997	7.18	2.09
2024	701	467	935	6.88	1.99
2025	664	448	880	6.80	1.95
2026	643	438	848	6.46	1.84
2027	623	428	818	6.14	1.73
2028	594	411	777	5.84	1.62
2029	573	400	746	5.55	1.53
2030	553	389	717	5.45	1.49
2031	536	375	696	5.11	1.37
2032	513	358	668	4.80	1.26
2033	497	345	650	4.50	1.16
2034	483	334	633	4.22	1.07
2035	465	319	610	4.10	1.02
2036	450	307	593	4.04	1.00
2037	437	296	578	3.98	0.99
2038	418	280	555	3.92	0.97

Source: Siemens, NREL

6.6 Wind Projects

As per the order by the Puerto Rico Energy Bureau (PREB)[36], wind resources are evaluated to in the economic competition with all other options, including fossil and other renewables. The cost estimates for utility scale wind projects were developed with the following steps: 1) establish baseline onshore wind projects operating and overnight capital costs estimate; 2) evaluate interconnection costs specific to Puerto Rico; 3) assess construction and financing costs reflecting Puerto Rico specific assumptions; and 4) calculate Levelized Cost of Energy (LCOE) for wind projects in Puerto Rico.

6.6.1 Baseline Operating and Overnight Capital Costs

For step 1, the IRP assumes overnight capital costs and operating costs for onshore wind projects consistent with the NREL 2018 ATB as shown in Exhibit 6-40.

[36] Dated September 18, 2018

Exhibit 6-41. U.S. Utility Scale Wind Projects Costs Assumptions

NREL 2018 Annual Technology Baseline (ATB) Mid Case		
Year	Onshore Wind Overnight Capital Costs 2018$/KW	Fixed Operating Costs 2018$/kW-year
2018	1,731	52.36
2019	1,733	51.98
2020	1,736	51.60
2021	1,738	51.22
2022	1,741	50.83
2023	1,744	50.45
2024	1,747	50.07
2025	1,749	49.69
2026	1,752	49.31
2027	1,755	48.92
2028	1,758	48.54
2029	1,761	48.16
2030	1,764	47.78
2031	1,768	47.39
2032	1,771	47.01
2033	1,774	46.63
2034	1,777	46.25
2035	1,781	45.87
2036	1,784	45.48
2037	1,788	45.10
2038	1,792	44.72
2039	1,795	44.34

NREL 2018 Annual Technology Baseline (ATB) Low Case		
Year	Onshore Wind Overnight Capital Costs 2018$/KW	Fixed Operating Costs 2018$/kW-year
2018	1,733	51.22
2019	1,731	50.45
2020	1,716	49.69
2021	1,655	48.92
2022	1,592	48.16
2023	1,527	47.39
2024	1,459	46.63
2025	1,390	45.87
2026	1,318	45.10
2027	1,244	44.34
2028	1,120	43.57
2029	1,080	42.81
2030	1,048	42.04
2031	1,024	41.66
2032	1,009	41.28
2033	1,006	40.90
2034	1,004	40.51
2035	1,001	40.13
2036	998	39.75
2037	995	39.37
2038	993	38.99
2039	990	38.60

Source: NREL 2018 ATB, converted to $2018. (https://atb.nrel.gov/electricity/data.html)

6.6.2 Investment Tax Credit (ITC)

Consistent with the current policy, the IRP assumes the following: wind facilities that commence construction by December 31, 2018 will qualify for 18 percent ITC; wind facilities that commence construction by December 31, 2019 will be reduced to 12 percent ITC; and zero percent afterwards. [37]

6.6.3 Project Development and Construction Time

The IRP assumes an accelerated timeline for wind projects similar to the solar PV projects, assuming 12 months for the development period (request for proposal, bid evaluation, permitting, and financing) and 12 months for construction.

6.6.4 Levelized Cost of Energy (LCOE)

For the IRP modeling, the levelized cost of energy (LCOE) is calculated as the net present value of the unit-cost of energy over the lifetime of the wind asset. The LCOE is then used as a proxy for the average price that the wind project could break even over its lifetime. Exhibit 6-41 shows the LCOE of wind under Mid case and Low case, determined using NREL's projected improvements of capacity factors for wind on their 2018 ATB's TRG-8 forecast that matches the wind conditions in Puerto Rico (Starts in 2016 with 25% Capacity Factors).

[37] http://programs.dsireusa.org/system/program/detail/658

Exhibit 6-42. Levelized Cost of Energy (LCOE) of Wind

Wind Levelized Cost of Energy in Puerto Rico (CRG-8 CF)		
Commercial On Line (COD) Year	Mid Case Wind 2018$/MWh	Low Case Wind 2018$/MWh
2018	104	103
2019	105	98
2020	110	100
2021	121	106
2022	119	100
2023	117	94
2024	116	89
2025	114	84
2026	112	79
2027	111	74
2028	109	67
2029	108	64
2030	107	62
2031	106	60
2032	104	58
2033	103	57
2034	102	56
2035	101	55
2036	100	55
2037	99	54
2038	99	53

Note: Commercial on line year

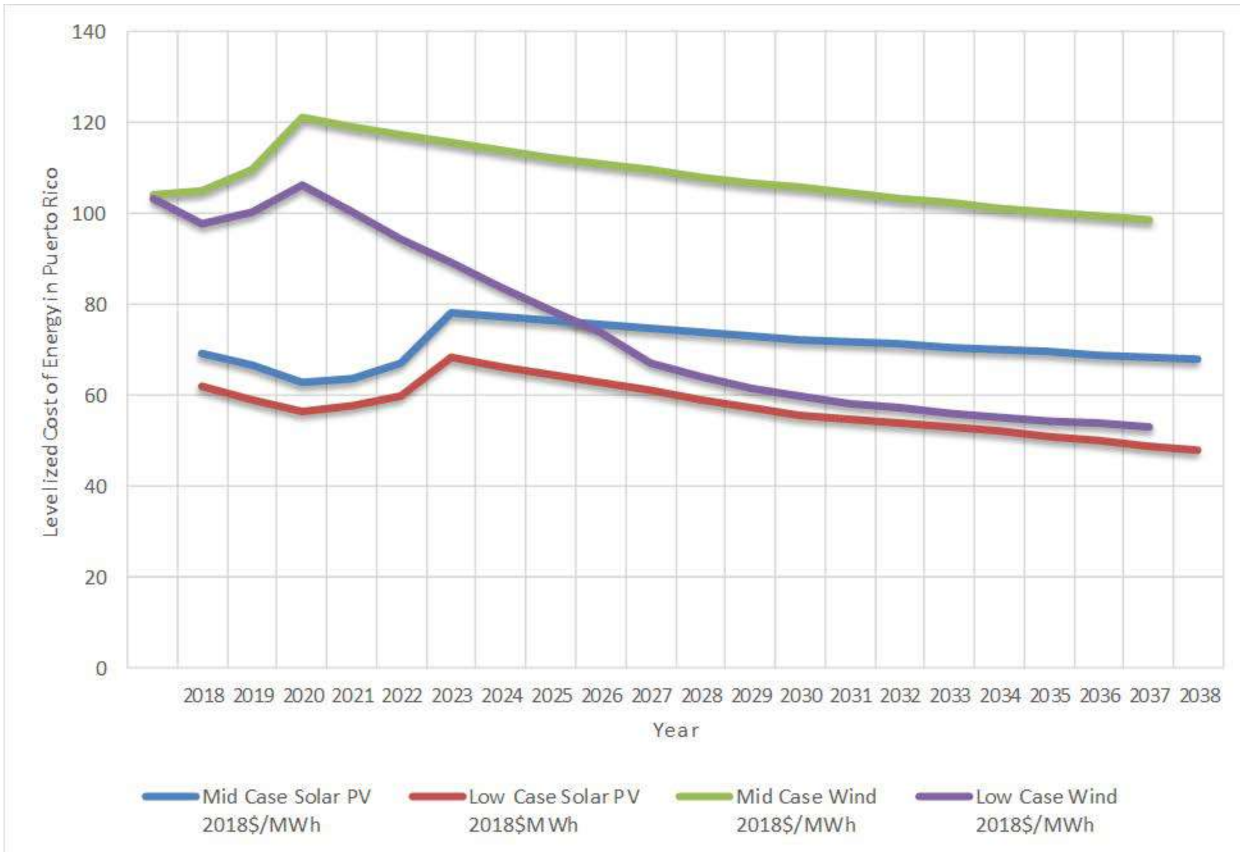
See workpaper: PREPA IRP Solar Wind Storage Costs-Updated CF-Wind-final.xlsm

Exhibit 6-42 shows a comparison of the LCOE of wind with Solar PV. Note that the Low Case for Wind is slightly higher than the Low Case for Solar PV but lower than the Mid Case for Solar PV. In our analysis of Low Cases we did see small amounts of wind added to meet the system requirements.

Finally, Exhibit 6-44 and Exhibit 6-45 show the LCOE calculation for the Mid Case and Low Case, respectively, for Wind Turbine generation.

As can be observed the Mid Case and the Low Case consider a continued improvement in the capacity factor for wind. In the Mid Case the capacity factor escalates from 26% to 33% and in the low case from escalates through the years from 25% to 39%.

Exhibit 6-43. Wind and Photovoltaic Levelized Cost of Energy (LCOE) $2018/MWh



See workpaper: PREPA IRP Solar Wind Storage Costs-Updated CF-Wind-final.xlsm

Exhibit 6-44. Levelized Cost of Energy (LCOE) of Wind Generation – Base Case

Commercial on line year		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2038
Construction Start Year		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034	2037
Capital and Operating Costs															
Overnight Cost, US National, 100 MW	$2018/Watt	1.73	1.74	1.74	1.74	1.74	1.75	1.75	1.75	1.76	1.76	1.76	1.76	1.78	1.79
Puerto Rico Adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Overnight Cost, Puerto Rico, 100 MW	$2018/Watt	2.01	2.01	2.02	2.02	2.02	2.03	2.03	2.03	2.04	2.04	2.04	2.05	2.07	2.08
IDC Cost Adder	%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
All-In Cost, Puerto Rico, 100 MW, $/Wac	$2018/Watt	2.06	2.06	2.07	2.07	2.07	2.08	2.08	2.08	2.09	2.09	2.09	2.10	2.12	2.13
Small Scale Adder (30 MW)	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Base Cost, Puerto Rico, 30 MW	$2018/Watt	**2.06**	**2.06**	**2.07**	**2.07**	**2.07**	**2.08**	**2.08**	**2.08**	**2.09**	**2.09**	**2.09**	**2.10**	**2.12**	**2.13**
Fixed O&M	$2018/kW-yr	67.58	67.08	66.58	66.08	65.59	65.09	64.59	64.10	63.60	63.10	62.61	62.11	59.63	58.13
30 MW Wind Project Parameters															
Capacity	MW	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Capacity Factor	%	26%	27%	27%	28%	28%	29%	29%	29%	30%	30%	30%	31%	32%	33%
Energy Produced	MWh	69,458	70,624	71,766	72,884	73,979	75,051	76,099	77,123	78,123	79,100	80,054	80,983	85,278	87,572
Base Capital System	$2018 thousand	61,806	61,895	61,986	62,080	62,176	62,274	62,375	62,477	62,582	62,689	62,798	62,910	63,500	63,881
Interconnection Costs	$2018 thousand	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840
Total System Capital Costs	$2018 thousand	64,646	64,735	64,827	64,920	65,016	65,115	65,215	65,317	65,422	65,529	65,639	65,750	66,341	66,722
ITC	%	18%	12%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Income Tax	%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%
Capital Recovery Factor	%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%
Project Financing Factor	%	86%	94%	109%	109%	109%	109%	109%	109%	109%	109%	109%	109%	109%	109%
Construction Financing Factor	%	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Annualized Capital Costs	$2018 thousand	**5,267**	**5,745**	**6,695**	**6,705**	**6,715**	**6,725**	**6,735**	**6,746**	**6,756**	**6,767**	**6,779**	**6,790**	**6,851**	**6,891**
Fixed O&M	$2018 thousand	2,027	2,012	1,997	1,983	1,968	1,953	1,938	1,923	1,908	1,893	1,878	1,863	1,789	1,744
Total Base System Cost	$2018 thousand	**7,295**	**7,757**	**8,692**	**8,687**	**8,682**	**8,677**	**8,673**	**8,669**	**8,664**	**8,661**	**8,657**	**8,654**	**8,640**	**8,635**
Levelized Cost of Energy (Base)	$2018/MWh	**105**	**110**	**121**	**119**	**117**	**116**	**114**	**112**	**111**	**109**	**108**	**107**	**101**	**99**

See workpaper: PREPA IRP Solar Wind Storage Costs-Updated CF-Wind-final.xlsm

Exhibit 6-45. Levelized Cost of Energy (LCOE) of Wind Generation – Low Case

Commercial on line year		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2038
Construction Start Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034	2037
Capital and Operating Costs																
Overnight Cost, US National, 100 MW	$2018/Watt	1.73	1.73	1.72	1.65	1.59	1.53	1.46	1.39	1.32	1.24	1.12	1.08	1.05	1.00	0.99
Puerto Rico Adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Overnight Cost, Puerto Rico, 100 MW	$2018/Watt	2.01	2.01	1.99	1.92	1.85	1.77	1.69	1.61	1.53	1.44	1.30	1.25	1.22	1.16	1.15
IDC Cost Adder	%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
All-In Cost, Puerto Rico, 100 MW, $/Wac	$2018/Watt	2.06	2.06	2.04	1.97	1.89	1.81	1.73	1.65	1.57	1.48	1.33	1.28	1.25	1.19	1.18
Small Scale Adder (30 MW)	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Base Cost, Puerto Rico, 30 MW	$2018/Watt	**2.06**	**2.06**	**2.04**	**1.97**	**1.89**	**1.81**	**1.73**	**1.65**	**1.57**	**1.48**	**1.33**	**1.28**	**1.25**	**1.19**	**1.18**
Fixed O&M	$2018/kW-yr	66.58	65.59	64.59	63.60	62.61	61.61	60.62	59.63	58.63	57.64	56.64	55.65	54.66	52.17	50.68
30 MW Wind Project Parameters																
Capacity	MW	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Capacity Factor	%	25%	28%	29%	30%	31%	31%	32%	33%	33%	34%	35%	35%	36%	38%	39%
Energy Produced	MWh	65,700	73,913	76,077	78,172	80,197	82,152	84,038	85,854	87,600	89,277	90,884	92,421	93,889	100,182	103,121
Base Capital System	$2018 thousand	61,787	61,721	61,180	59,003	56,755	54,431	52,029	49,551	46,995	44,362	39,926	38,495	37,360	35,685	35,390
Interconnection Costs	$2018 thousand	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840	2,840
Total System Capital Costs	$2018 thousand	64,627	64,562	64,020	61,843	59,596	57,271	54,870	52,391	49,836	47,203	42,766	41,335	40,201	38,525	38,230
ITC	%	24%	18%	12%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Income Tax	%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%
Capital Recovery Factor	%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%
Project Financing Factor	%	79%	86%	94%	109%	109%	109%	109%	109%	109%	109%	109%	109%	109%	109%	109%
Construction Financing Factor	%	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Annualized Capital Costs	$2018 thousand	**4,796**	**5,260**	**5,681**	**6,387**	**6,155**	**5,915**	**5,667**	**5,411**	**5,147**	**4,875**	**4,417**	**4,269**	**4,152**	**3,979**	**3,948**
Fixed O&M	$2018 thousand	1,997	1,968	1,938	1,908	1,878	1,848	1,819	1,789	1,759	1,729	1,699	1,670	1,640	1,565	1,520
Total Base System Cost	$2018 thousand	**6,794**	**7,228**	**7,619**	**8,295**	**8,033**	**7,763**	**7,485**	**7,199**	**6,906**	**6,604**	**6,116**	**5,938**	**5,791**	**5,544**	**5,469**
Levelized Cost of Energy (Base)	$2018/MWh	**103**	**98**	**100**	**106**	**100**	**94**	**89**	**84**	**79**	**74**	**67**	**64**	**62**	**55**	**53**

See workpaper: PREPA IRP Solar Wind Storage Costs-Updated CF-Wind-final.xlsm

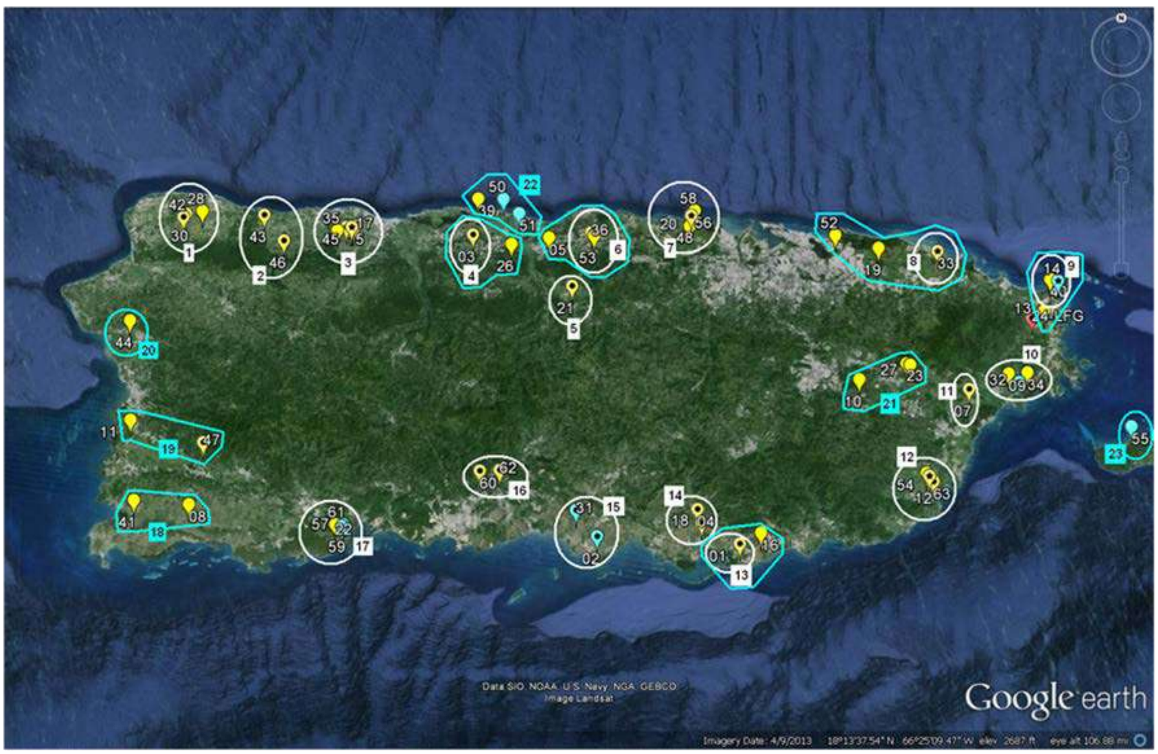
6.7 Renewable Solar and Wind Profiles

Siemens developed the wind and solar generation profiles provided in the workpapers under the folder “Renewable Resource 8760 Profiles” following the general procedure presented below.

The renewable solar and wind 8760-Hour profiles used to represent the renewable generation in the AURORA Long-Term Capacity Expansion (LTCE) plan and the AURORA nodal modelling were developed from data derived from the meteorological models developed by AWS Truepower (AWS) as a part of the PREPA Renewable Study (the Study).

The 8760-hour irradiance and wind profiles were developed by AWS in 60-minute and 10-minute intervals for multiple site locations in Puerto Rico. The following map provides the solar and wind sites considered. This data was used for the development of the corresponding wind and PV profiles.

Exhibit 6-46. Location of points for development of meteorological data.



6.7.1 Generic Solar Modeling

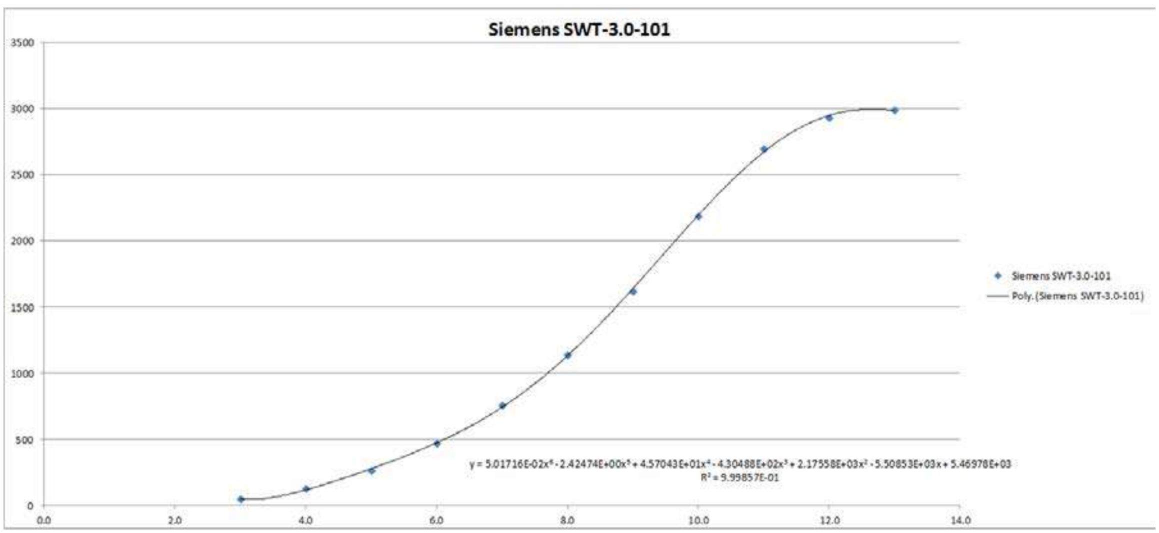
For the generic solar site, the meteorological data was converted to a MW output profile using the PVSyst program. The program determines hourly megawatt output at a site based on actual/assumed solar equipment, sizing, and placement to determine the hourly output at a site. A generic set of equipment was selected and approved by PREPA. The typical sizing was also determined based on utility scale site. Generic sites were defined with specific locations in the PREPA system. This profile represents the expected irradiance changes at

various locations in the island and the (8760-Hour) profile was normalized so that a generic 60-MW site could be installed by the LTCE with its dependence only on the zone for location. The profiles were adjusted to represent the projected 22% capacity factor in the island using PROMOD that while maintaining the overall shape and the maximum capacity, develops a curve that has the desired energy.

6.7.2 Generic Wind Modeling

The AWS wind speed data (wind speed at 80-meters elevation) was converted to an 8760-Hour Megawatt profile using the and a WTG power curve equation. In the course of work for the Renewable study multiple WTG models were reviewed before a generic model was selected/determined and agreed with PREPA that provides a reasonable depiction of wind output given a specified area/zone wind profile. Below a power curve is shown for the Siemens SWT-3.0-101 Wind Turbine Generator (WTG). Note that a wind speed below 3 m/s and at wind speeds higher than 12 m/s the output is zero. Common to most WTG's, this WTG is inoperative below 3-m/s wind speeds and is subject to stress damage above 12-m/s wind speeds which is also common in multiple WTGs.

Exhibit 6-47: Siemens SWT – 3.0 – 101 Wind Turbine Power Curve and Equation[38]



The AWS wind speed models for various sites on the island were used to determine the generic wind 8760-Hour profile for each area/zone. The generic power curve equation was utilized for each of the AWS models to determine a normalized (1-MW) 8760-Hour megawatt profile for each of the areas/zones. This allows the LTCE run to select where to put a proposed wind site utilizing the specific profile for the specific area/zone modeled.

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[38] Siemens SWT – 3.0- 101 Wind Turbine Power Curve and Equation from the Siemens SWT – 3.0- 101 tab of the Report Tables and Graphs.xlsx spreadsheet. This information is also provided in the PREPA Renewable Study report. This information is also found in the AWS WIND SITE.xlsx spreadsheet.

Wind profiles were updated to achieve the desired capacity factor as forecasted in by NREL in TRG-8. This was accomplished utilizing the PROMOD program to adjust the capacity factor while maintaining the maximum capability and general shape or profile of the generic wind site(s).

For practical reasons the NREL TRG-8 capacity factor projection was approximated in three levels for each Zone. For the mid case the following factors were used and applied to the sites in the subsequent exhibit:

- 2020 – 2022 at 28% capacity factor
- 2023 – 2029 at 30% capacity factor
- 2030 – 2038 at 33% capacity factor

Exhibit 6-48: MID Wind Capacity Factor Profiles Developed for the LTCE Analysis[39]

MiniGrid Zone	MID - 2020-2022 Wind Models	MID - 2023-2029 Wind Models	MID - 2030-2038 Wind Models
Arecibo	AWS Site 22 @ 28% CF	AWS Site 22 @ 30% CF	AWS Site 22 @ 33% CF
Bayamon	AWS Site 07 @ 28% CF	AWS Site 07 @ 30% CF	AWS Site 07 @ 33% CF
Caguas	AWS Site 10 @ 28% CF	AWS Site 10 @ 30% CF	AWS Site 10 @ 33% CF
Carolina	AWS Site 10 @ 28% CF	AWS Site 10 @ 30% CF	AWS Site 10 @ 33% CF
Cayey	AWS Site 10 @ 28% CF	AWS Site 10 @ 30% CF	AWS Site 10 @ 33% CF
Mayaguez North	AWS Site 22 @ 28% CF	AWS Site 22 @ 30% CF	AWS Site 22 @ 33% CF
Mayaguez South	AWS Site 22 @ 28% CF	AWS Site 22 @ 30% CF	AWS Site 22 @ 33% CF
Ponce ES	AWS Site 15 @ 28% CF	AWS Site 15 @ 30% CF	AWS Site 15 @ 33% CF
Ponce OE	AWS Site 17 @ 28% CF	AWS Site 17 @ 30% CF	AWS Site 17 @ 33% CF
San Juan	AWS Site 07 @ 28% CF	AWS Site 07 @ 30% CF	AWS Site 07 @ 33% CF

For the Low Case the following factors were used:

- 2020 – 2022 at 31% capacity factor
- 2023 – 2029 at 34% capacity factor
- 2030 – 2038 at 39% capacity factor

[39] MID Wind Capacity Factor Profiles Developed for the LTCE Analysis from the Capacity Factor Requirements tab of the Report Tables and Graphs.xlsx spreadsheet. The 8760-hour profiles can be found in the Generic Wind Profiles 20190418.xlsx spreadsheet.

Exhibit 6-49: LOW Wind Capacity Factor Profiles Developed for the LTCE Analysis[40]

MiniGrid Zone	LOW - 2020-2022 Wind Models	LOW - 2023-2029 Wind Models	LOW - 2030-2038 Wind Models
Arecibo	AWS Site 22 @ 31% CF	AWS Site 22 @ 34% CF	AWS Site 22 @ 39% CF
Bayamon	AWS Site 07 @ 31% CF	AWS Site 07 @ 34% CF	AWS Site 07 @ 39% CF
Caguas	AWS Site 10 @ 31% CF	AWS Site 10 @ 34% CF	AWS Site 10 @ 39% CF
Carolina	AWS Site 10 @ 31% CF	AWS Site 10 @ 34% CF	AWS Site 10 @ 39% CF
Cayey	AWS Site 10 @ 31% CF	AWS Site 10 @ 34% CF	AWS Site 10 @ 39% CF
Mayaguez North	AWS Site 22 @ 31% CF	AWS Site 22 @ 34% CF	AWS Site 22 @ 39% CF
Mayaguez South	AWS Site 22 @ 31% CF	AWS Site 22 @ 34% CF	AWS Site 22 @ 39% CF
Ponce ES	AWS Site 15 @ 31% CF	AWS Site 15 @ 34% CF	AWS Site 15 @ 39% CF
Ponce OE	AWS Site 17 @ 31% CF	AWS Site 17 @ 34% CF	AWS Site 17 @ 39% CF
San Juan	AWS Site 07 @ 31% CF	AWS Site 07 @ 34% CF	AWS Site 07 @ 39% CF

As shown in the tables above, five basic profiles were used to define the wind profiles for each of the zones: AWS Sites 07, 10, 15, 17 and 22[41]. This was done out of practicality as well as functionality. The practical measure is that the profiles are not that different between the areas as the wind naturally blankets the island. The functionality measure comes in that the AURORA program requires much more time to process the larger the number of profiles.

The actual 8760-hour profiles are provided in the workpapers of this IRP .

[40] LOW Wind Capacity Factor Profiles Developed for the LTCE Analysis is from the Capacity Factor Requirements tab of the Report Tables and Graphs.xlsx spreadsheet. The 8760-hour profiles can be found in the Generic Wind Profiles 20190418.xlsx spreadsheet.

[41] The AWS Truepower meteorological data can be found in the AWS WIND SITES.xlsx spreadsheet.

6.8 Considerations for Offshore Wind

Offshore Wind was considered but it not included since it is expected to have cost higher than the equivalent Solar PV project.

With respect of Onshore Wind, we can indicate the following:

- A search for information on offshore wind found lack of reliable data to suggest that the offshore wind in Puerto Rico would be comparable to locations in the northwest United States or Europe, that are rich on this resource. The search considered location, permitting feasibility, project costs, resulting energy prices, etc.

- Preliminary studies[42] for Puerto Rico do identify potential offshore wind locations but the projected costs are significantly higher than those associated with solar PV or wind installations on the island. This study indicated that “including the additional costs to produce offshore wind energy, the expected end cost of energy due to offshore wind energy production in Puerto Rico could reach similar to the current cost of energy in the Island. Therefore, it is unlikely that offshore wind energy is a viable near term option to the solution of the energy crisis in Puerto Rico”[43]. Further, the study concluded that if cost reductions are made in offshore wind technology, then this technology may become viable in the future.

- Further analysis to study offshore wind could be initiated but this would require an expensive and time-consuming study. The time requirements alone place this technology out of reach to meet the current time requirements for this IRP.

- This IRP does include substantial amounts of solar PV installations. If offshore wind were to become practical and cost-competitive with solar PV installations, then we would expect some of the solar PV installations to be replaced by offshore wind. As previously noted, the cost and availability of the solar PV versus wind must show that wind is a lower cost alternative to justify its inclusion over solar PV. Our study analysis shows only a fraction of conditions where wind is included in the results.

[42] The United States Department of Energy, Energy Information Administration, included a Puerto Rico Analysis citing the following study relating to offshore wind: Preliminary Cost Assessment for Offshore Wind Energy in Puerto Rico, Héctor M. Rodríguez, Ph.D., P.E., Gerardo Carbajal, Ph.D., and Edwar Romero, Ph.D., Universidad del Turabo, Puerto Rico, July 2015, page 5, Collaborative effort between the DOE/NREL Wind Repowering America Program, AWS Truewind and the Commonwealth of Puerto Rico.

[43] Preliminary Cost Assessment for Offshore Wind Energy in Puerto Rico, Page 7, Section VII. Conclusions, Paragraph 3.

Part
7

Assumptions and Forecasts

This Part provides two remaining aspects necessary for the IRP, fuel infrastructure forecast and an estimation of the Value of Lost Load (VOLL) for Puerto Rico.

7.1 Fuel Infrastructure and Forecast

7.1.1 Fuel Infrastructure Options

The purpose of this review is to identify the requirements for using or developing the fuel infrastructure needed to support the generation options considered in the IRP. Specific objectives include:

- Identify current fuel infrastructure options;
- Evaluate sources of natural gas delivered to Puerto Rico such as liquefied natural gas (LNG);
- Identify LNG or natural gas transport infrastructure needs relative to key generation sites at Aguirre and Costa Sur in the south, San Juan and Palo Seco in the north, Mayagüez in the west, and Yabucoa in the east; and
- Review alternative liquid fuels' attractiveness and deliverability.

As a power generation fuel, natural gas is superior to petroleum products like diesel and residual fuel oil because it has lower air emissions, higher efficiency, greater operating flexibility, and lower costs. The inherent sulfur and particulate content of natural gas processed as LNG is extremely low. Carbon dioxide emissions from natural gas combustion are also lower relative to liquid fuels.[44] With state-of-the-art controls such as low-NO_x burners, NO_x emissions can be lower as well. Natural gas allows the use of advanced combined cycle technology (although diesel can be used as a fuel for less advanced combined cycle technology), which is the most fuel-efficient thermal power generation technology available today.[45] Advanced gas turbines cannot fire residual fuel oil because of its high ash content. In addition, natural gas has been significantly less expensive since 2009 compared to premium liquid fuels such as diesel and residual fuel oil, primarily due to the shale gas boom in the U.S. (see Exhibit 7-2). However, the benefits of natural gas can be realized only if it can be delivered in a cost-effective manner to Puerto Rico and then distributed to power generation sites. The need to expand the island's LNG import capability and natural gas distribution

[44] According to the EIA (https://www.eia.gov/environment/emissions/co2_vol_mass.php), natural gas emits 67%, 73%, and 84% of the CO_2 as compared to residual fuel oil, diesel, and propane, respectively.

[45] The EIA (https://www.eia.gov/electricity/annual/html/epa_08_02.html) reports that current natural gas-fired combined cycle plants have an average heat rate of 7,652 Btu/kWh vs. 9,179 Btu/kWh for internal combustion and 11,214 Btu/kWh for gas turbine.

pipelines would require significant new fuel infrastructure investments in order to realize Puerto Rico's potential benefit from greater natural gas use for power generation.

The U.S. mainland currently has two LNG export terminals in operation and four more under construction; collectively representing 71.05 million tons per annum (MMtpa) of nameplate capacity that will be online by 2021. More than 300 MMtpa of additional capacity has been proposed, most of which will not be realized but some of which may constitute a second wave of liquefaction capacity buildout in the mid- to late-2020s. Exhibit 7-1 below describes the existing LNG capacity in the mainland U.S. The total contracted capacity is equal to 63.08 MMtpa or 88.8% of nameplate capacity. While this leaves nearly 8 MMtpa of uncontracted capacity that could potentially satisfy Puerto Rico's LNG demand (estimated to be no higher than 6.5 MMtpa), these U.S.-based LNG export facilities would require Jones Act-compliant ships to ferry LNG to Puerto Rico. The Jones Act requires goods traveling between U.S. ports to do so on ships constructed and flagged in America, with primarily U.S. crews. However, there are not any Jones Act-compliant, large-scale U.S. vessels that can carry LNG in large onboard tanks. In addition, no American shipyard has constructed an LNG carrier in nearly four decades (although there are U.S. vessels that could carry LNG in ISO containers). This reason, among others, is why Puerto Rico primarily receives its LNG supply from Trinidad & Tobago. Exhibit 7-1 summarizes total and contracted U.S. export facility capacity by terminal.

Exhibit 7-1. U.S. Mainland Large-Scale LNG Export Capacity (MMtpa)

LNG Facility	Status	Nameplate Capacity	Contracted Capacity
Sabine Pass	Operational	22.5	19.8
Dominion Cove Point	Operational	5.3	4.6
Freeport	Under Construction	15.3	13.6
Cameron	Under Construction	12.0	12.0
Corpus Christi	Under Construction	13.5	10.6
Elba Island	Under Construction	2.5	2.5

Source: Siemens.

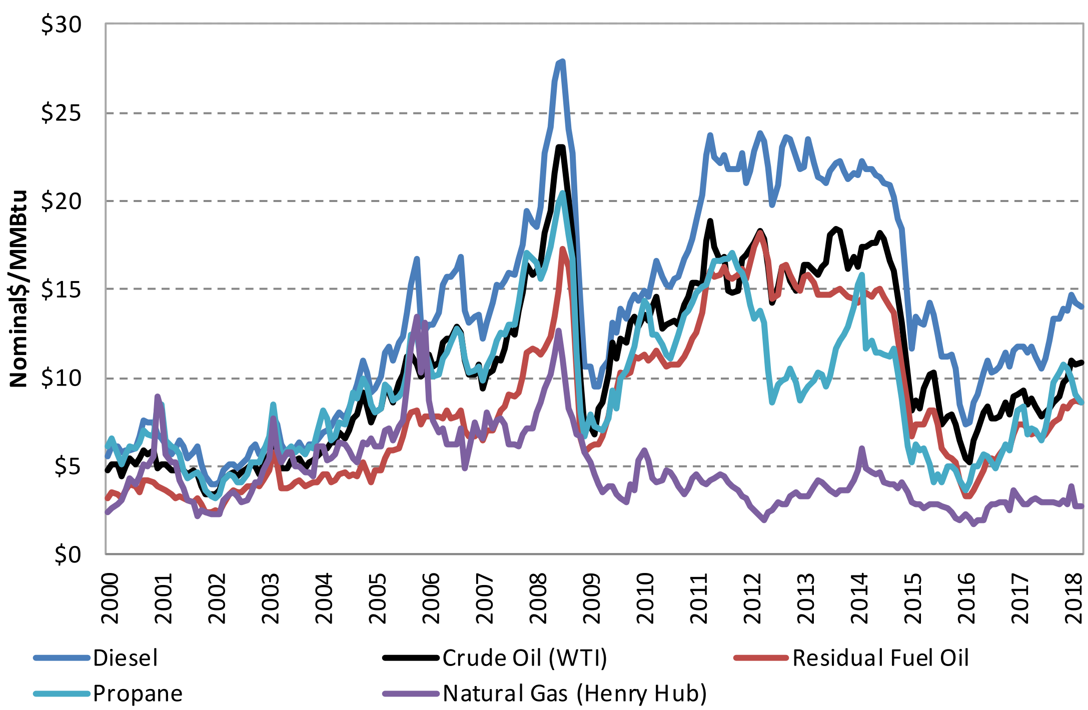
LNG terminals and infrastructure can play an important role in sourcing cleaner and less expensive LNG. Robust options for natural gas supply provide flexibility to enhance security of supply (backup) to each generating site, as well as commercial value in negotiating and selecting the most advantageous pricing over time among various fuel suppliers.

The EcoEléctrica LNG Import Terminal has been operating successfully since 2000. In 2017, the Federal Energy Regulatory Commission (FERC) approved a change in operations to expand the terminal's natural gas send-out beyond its own 507 MW combined cycle unit to include supply to PREPA's 820 MW Costa Sur generating plant. The terminal send-out capacity was increased by 93 MMcf/d, from 186 MMcf/d to 279 MMcf/d, by putting into service an idle gasifier (the third such gasifier) and can be expanded by a further 93 MMcf/d by putting into service the remaining spare gasifier (the fourth such gasifier). EcoEléctrica delivers 186 MMcf/d of regasified LNG to the Costa Sur plant through a renegotiated contract (as of May 2018, Costa Sur is running exclusively on natural gas) while the remaining 93 MMcf/d supplies its own combined cycle plant. Beyond the maximum send-out capacity of 372 MMcf/d (if the fourth gasifier is put into service), a major increase in LNG terminal

throughput could require some modifications, possibly including a second LNG storage tank[46]. It must be noted that EcoEléctrica is a private company and expanded natural gas supply from this terminal would require PREPA, at a minimum, to contractually commit to a long-term natural gas processing and/or purchase agreement to justify infrastructure investments.

Fuel (including diesel and residual fuel oil) together with purchased power is the predominant cost and most volatile rate component for PREPA. Reducing dependence on oil for power generation has long been a top priority for PREPA. Although progress has been made, oil remains the main source of energy generation. An estimated 45% of generation is from oil, compared to the national average of 4%. PREPA has an aspirational goal of a 20-25% cost reduction ($400-500 million) from fuel and purchased power under pre-storm conditions by FY 2023. One component, purchased power, is under two long-term Power Purchase Agreements (PPAs) that extend through 2022 and 2027, respectively, and thus are not easily altered. Fuel prices are the other component and have been historically volatile, particularly oil and its derivative diesel and residual fuel oil products. Prices have been increasing since a recent low point in 2016. Exhibit 7-2 below provides a comparison of the U.S. fuel prices from 2000 to March 2018 on an energy-equivalent nominal $/MMBtu basis. Natural gas has been the least-cost of these five fuels consistently for nearly a decade and in more recent history has exhibited significantly less price volatility.

Exhibit 7-2. U.S. Fuel Prices (Nominal $/MMBtu)



[46] A second LNG tank was included in the original permit but was not constructed, and the permit has expired. So, a new permitting effort would be required for such an expansion.

Source: Siemens, EIA.

Puerto Rico's electrical infrastructure was critically damaged during September 2017, when Hurricanes Irma and Maria delivered back-to-back blows to the Island, resulting in a complex and prolonged disaster recovery effort. Hurricane Irma skirted the northern coast of the Island from September 6–7, 2017 as a Category 5 storm, causing significant flooding, regional power and water outages, and other impacts to the Island's infrastructure. Exactly 13 days later, on September 20th, and before Irma's response operations had concluded, Hurricane Maria slammed into Puerto Rico, making a direct strike as a strong Category 4 storm causing widespread devastation.

The following sections describe the pre-storm fuel infrastructure as well as proposed fuel infrastructure during the recovery and rebuilding phases after the storms.

7.1.2 Pre-Storm Fuel Infrastructure

7.1.2.1 Residual Fuel Oil (No. 6 Fuel Oil)

Puerto Rico has three steam-electric power plants which burn residual fuel oil. These are Palo Seco and San Juan in the north and Aguirre located on the south coast. The Costa Sur plant, located on the southwestern coast, is dual-fuel, capable of burning either residual fuel oil or natural gas. However, as of May 2018 it is burning exclusively natural gas. The San Juan and Aguirre facilities have additional combined-cycle plants that burn diesel. Residual fuel oil is delivered to Puerto Rico by vessel. It is stored centrally at the former Commonwealth Oil Refinery complex on the south-west side of the island. From there, it is piped to the nearby Costa Sur plant and delivered by barge to the other three plants. Each of the three steam-electric plants has onsite storage for residual fuel oil. Palo Seco has capacity to store 450,000 barrels, San Juan 138,000 barrels, and Aguirre 780,000 barrels. Costa Sur has 800,000 barrels of storage that could be converted for other use. Based on 2013 generation Exhibits, this storage capacity represents approximately a 36-day supply for Palo Seco, 14 day supply for San Juan, and 40 day supply for Aguirre. The plants typically hold at least 15 days of fuel supply onsite.

7.1.2.2 Diesel (No. 2 Fuel Oil aka Distillate Fuel Oil)

Diesel is used at the combined-cycle units at Aguirre and San Juan and the combustion-turbine units at Cambalache, Mayagüez, and nine other small facilities around the island. Diesel fuel is delivered to storage facilities at Yabucoa and Bayamon and from there is barged to four larger stations (Aguirre, San Juan, Cambalache and Mayagüez). The nine other small facilities around the island operate infrequently and receive fuel deliveries by truck when required. The San Juan 2x200 MW combined cycle diesel-fired Units 5 and 6 have an attractive heat rate and could be converted to burn natural gas for a relatively modest investment of $10-30 million. If San Juan natural gas delivery is established, it is likely that San Juan Units 7, 8, 9, and 10 could be replaced with more efficient units. The Yabucoa facility has storage capacity for four million barrels of crude oil, fuel oil, and refined products. The Bayamon facility has storage capacity for 3.5 million barrels. A 2013 report indicates that there are two diesel fuel transfer lines between the Palo Seco and San Juan plants that are in service. There is no information regarding onsite storage for diesel at any of the other plants.

7.1.2.3 Natural Gas

Natural gas is used at the privately-owned EcoEléctrica cogeneration facility and at the Costa Sur steam plant, which are both located at Guayanilla Bay on the southwestern coast where

the Peñuelas terminal and regasification facility is located. Natural gas is imported as LNG, mainly from Trinidad and Tobago (92% since 2010, under a 20-year contract for 0.5 MMtpa expiring in 2019, according to Energy Velocity). The EcoEléctrica plant is adjacent to the regasification facility and the Costa Sur plant receives gas via a short pipeline. The 2017 expansion of regasification facilities at EcoEléctrica LNG Import Terminal allows Costa Sur, which has dual-fuel units, to also be fully fired by LNG. As of May 2018, Costa Sur is now burning exclusively natural gas. There is a substantial take-or-pay gas contract in place that requires significant generation from Costa Sur.

Storage for one million barrels of LNG is available at the regasification facility. Based on the original FERC application, EcoEléctrica was approved to construct two, one-million-barrel (160,000 cubic meters) LNG storage tanks. However, the second storage tank was never constructed and FERC authorization to construct the second tank has lapsed. However, the space remains available to construct the second tank if needed. Prior to 2017, the facility had two spare regasifiers. In 2017, it obtained FERC approval to put one of them into continuous service and to increase total sendout capacity from the import terminal to 279 MMcf/d. This increased LNG cargo (ship) deliveries to 40 per year from 24 per year. The FERC approval of the third gasifier allowed the gas received by Costa Sur to double to 186 MMcf/d from 93 MMcf/d. The remaining spare (fourth) gasifier also has a capacity of 93 MMcf/d, which would increase total plant sendout to 372 MMcf/d if put into service. Some steps were taken prior to 2013 to convert some of the other steam plants to natural gas, but these were put on hold due to uncertain gas supply following the hurricanes and cancellation of a cross-island pipeline project. There were also pre-existing plans to build the Aguirre Offshore GasPort, a floating storage and regasification unit offshore near the Aguirre plant that would be operational no later than January 1, 2022 and to convert the Aguirre plant to natural gas, but that project is not proceeding.

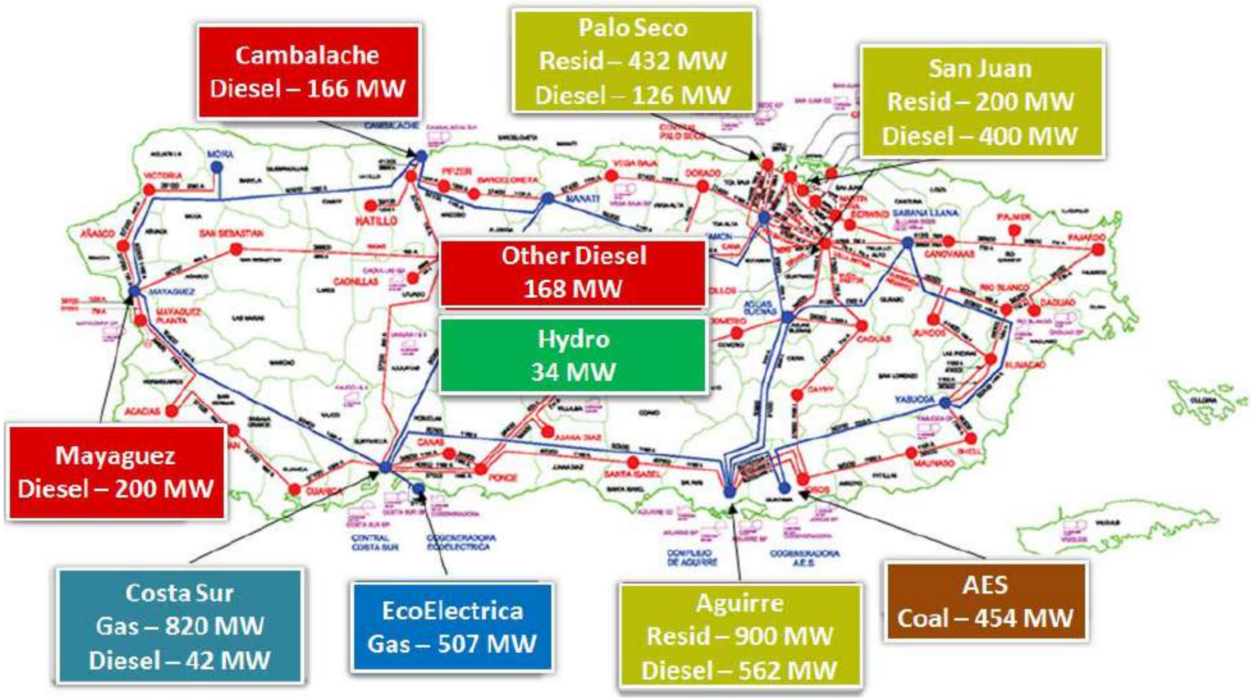
7.1.2.4 Coal

The privately-owned AES-Puerto Rico facility burns Colombian bituminous coal. The coal is delivered to Puerto Rico at the Las Mareas Port, just south of the plant site and is transported to the plant via covered conveyors. AES maintains a 30-day inactive coal storage supply to address potential delivery interruptions and a 20-day active storage supply.

7.1.2.5 Independent Power Production

IPP generation contributions to the island is contracted through 2022 for EcoEléctrica's 507 MW and 2027 for AES' 454 MW. Locations of the electric generating units in Puerto Rico are presented in Exhibit 7-3.

Exhibit 7-3. Current PREPA Generating Map



Source: PREPA, Siemens

7.1.2.6 Proposed Fuel Infrastructure and Natural Gas-Fired Generation Changes

Currently, only 22 percent of PREPA-owned generation is natural gas-fired. In the aftermath of the hurricanes, PREPA is considering options for new infrastructure, including the possibility to convert certain diesel or residual fuel oil units to natural gas. Such conversions would help to meet the requirements under the U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS) regulations as well as to take advantage of abundant and low-cost natural gas from the mainland. One such option is to convert San Juan Units 5 and 6, which represent 400 MW of relatively new (2008) and reliable baseload generation, from expensive diesel to cheaper natural gas in the form of LNG. The estimated total annual fuel requirements for these two units would be on the order of 24-25 TBtu/yr., assuming a heat rate of 7,652 Btu/kWh and a capacity factor of 89-93%. To facilitate conversion, the San Juan plant would require a natural gas receiving, storage, and supply system.

In addition to possible natural gas-fired generation changes, PREPA is considering several fuel infrastructure options in its 2018 IRP. These options include the following, in no implied priority:

- Aguirre Offshore GasPort
- Ship-based LNG at San Juan with pipeline to Palo Seco
- Land-based LNG at San Juan with pipeline to Palo Seco
- Ship-based LNG at Mayagüez (west)
- Ship-based LNG at Yabucoa (east)

- LNG or compressed natural gas (CNG) delivery to San Juan and potentially Palo Seco
- Additional regasification capacity and new natural gas pipelines, first from EcoEléctrica LNG Import Terminal to Aguirre and then to San Juan
- No new gas infrastructure

This analysis reviews the many considerations surrounding these options without presupposing that any option is a required solution for supporting projected electricity demand or for compliance with any regulatory requirements. This section is followed by a section discussing these fuel infrastructure Scenarios and the issues and considerations reflecting each Scenario.

7.1.2.7 Aguirre Offshore GasPort

On April 17, 2013, Aguirre Offshore GasPort, LLC (Aguirre LLC), a wholly-owned subsidiary of Excelerate Energy, LP, filed an application with FERC to develop a floating offshore LNG regasification facility called Aguirre Offshore GasPort (AOGP) to supply natural gas to PREPA's existing Aguirre Power Complex in Salinas, Puerto Rico. The AOGP facility would consist of an offshore berthing platform, a floating storage and regasification unit (FSRU), and a 4-mile-long, 21-inch outside diameter subsea pipeline connecting to the Aguirre Power Complex. AOGP was being developed with cooperation between Excelerate Energy, LP and PREPA.

Under the Aguirre LLC application, the AOGP would provide LNG storage capacity and sustained deliverability of natural gas to the Aguirre plant. The AOGP facility would assist PREPA's plan to convert the Aguirre plant from a residual fuel oil- and diesel-only plant to a facility capable of burning diesel and natural gas for the combined cycle units and heavy fuel oil and natural gas for the thermoelectric plant. The AOGP facility would have LNG storage capacity of 3.2 Bcf (150,000 cubic meters) and a natural gas send out capacity of 500 MMcf/d (peaking deliverability of up to 600 MMcf/d) to the Aguirre plant. Based on data from Aguirre LLC, the estimated total construction period for AOGP facility was approximately 12 months, and total capital cost of AOGP facility was estimated (inflated to 2018$) at $403 million (including onshore and offshore components, permits, financing costs, etc.). This estimation does not include the capital cost related to fuel conversion of the Aguirre power plant which PREPA has estimated the annual fixed operating costs to be approximately $81.5 million, excluding debt service.

The existing Aguirre units include 1,462 MW of diesel- and residual fuel oil-fired generation. If converted to natural gas, the expectation is that the maximum capacity of gas-fired generation would be 1,076 MW. The maximum daily volume of natural gas estimated to be required for this converted capacity would equal 155 MMcf/d. For the purpose of forecasting delivered natural gas prices to Aguirre, Siemens used an offtaker pricing formula similar to those used by large-scale Gulf Coast LNG offtakers in order to represent the estimated delivered cost to supply gas to Aguirre via AOGP. This pricing formula ($Price\ of\ Natural\ Gas$ = 1.15 * Henry Hub + 4.35), together with the average daily gas burn volume at an 80% generation capacity factor, gives a range from $423 million to $639 million in annual fuel supply costs each year of operation. This gives a starting point for estimating the required revenues the power generation plant would require supporting the capital, operating, and financing costs for AOGP.

PREPA commissioned a detailed economic analysis of the AOGP project using four resource plans and three price Scenarios[47]. The analysis concluded that the AOGP base price Scenario (where the base price is derived from the U.S. Energy Information Administration's Annual Energy Outlook 2017) demonstrated the benefits of AOGP as compared to the No AOGP base price Scenario. The conclusion results from the AOGP base Scenario having lower overall system costs on the order of $3.42 billion due to higher fuel costs incurred without AOGP. A similar benefit-cost analysis conclusion in favor of the AOGP project was reached when using a high oil price Scenario both with and without full Renewable Portfolio Standard (RPS) compliance. However, the AOGP low oil price Scenarios both with and without full RPS compliance were found to have a higher system cost than without the AOGP project. Based on these results, the economic analysis recommended proceeding with the AOGP project and associated Aguirre unit conversions.

Immediately following the second hurricane in September 2017, the Governor of Puerto Rico declared a state of emergency due to the devastation of Hurricane Maria. The widespread damage inflicted by Hurricane Maria, resulted in the Puerto Rico Energy Commission[48] (PREC) issuing an order[49] (dated April 26, 2018 for Case No. CEPR-AP-2017-0001) staying all proceedings to allow PREPA to focus on restoring electric service, including the proceeding on the AOGP project. Prior to this event, in early July 2017, PREPA's Fiscal Oversight and Management Board (FOMB) filed for protection under Title III of PROMESA. Later in July 2017, Excelerate Energy LP, the contractor for the AOGP project, announced that it had canceled its contracts with PREPA to construct the natural gas terminal. As a result of these events, PREC delayed any consideration of AOGP until such time as PREPA decides to pursue the project as part of its 2018 IRP. PREPA's April 2018 fiscal plan assumed or considered AOGP and other natural gas supply options. If AOGP does not proceed, as is the case now, PREPA may consider other LNG supply options. In the meantime, residual fuel oil and diesel will continue to be primary fuels at Aguirre at a higher cost than for power generated using LNG.

A March 2017 Siemens PTI fuel delivery assessment[50] analyzed the feasibility of containerized LNG or CNG to the Aguirre power station absent the AOGP project. The assessment found that containerized LNG deliveries would require 193 ISO containers per day while CNG deliveries would require 617 containers per day to meet project demand at the power plant. As a result, LNG delivery in ISO containers to Aguirre, absent AOGP, was determined to be impractical due to the expected gas demand and the amount of container handling required on a daily basis and vessel deliveries required on an annual basis.

As mentioned earlier, the IRP will consider other LNG options to bring natural gas to the island and the AOGP is not currently being studied as part of the core IRP. It remains Siemens view that the possible benefits to the AOGP project (together with upgrades to the Aguirre generating plant to use natural gas) include lower overall system costs compared to current infrastructure in either a base case price or a high oil price Scenario. The AOGP

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[47] http://energia.pr.gov/wp-content/uploads/2017/05/PREPA-Ex-1.02-Part-1-Economic-Analysis-Report.pdf

[48] PREC is now known as the Puerto Rico Energy Bureau (PREB)

[49] http://energia.pr.gov/wp-content/uploads/2018/04/Final-Resolution-and-Order-CEPR-AP-2017-0001.pdf

[50] http://energia.pr.gov/wp-content/uploads/2017/05/PREPA-Ex-1-04-PREPA-Fuel-Delivery-Option-Assessment.pdf

options brings the befits of lower carbon emissions from the Aguirre generation plant by burning more natural gas compared to current emissions, greater flexibility and security in fuel supply options, the ability to repurpose AOGP infrastructure (the floating storage and regasification unit could be sold and moved), and the potential to increase PREPA-owned generation as IPP contracts roll off in 2022 and 2027. However, the AOGP option brings the risks of potential of sustained low-oil prices could render AOGP uneconomic, new fuel infrastructure that could be vulnerable to hurricanes, the possibility of a decreasing need for fossil generation as load decreases with further population out-migration or increases in energy efficiency and renewable energy penetration, and continued dependence on south-to-north electricity transmission to reach load centers on the north side of the Island.

PREPA has addressed some of the concerns raised by PREC following the last IRP filed in 2015. One such concern related to the overall economic benefit of AOGP, which was addressed in detail in the economic analysis mentioned previously[51] and found to be generally favorable. In addition, the present IRP addresses a second concern, namely that PREPA must perform a comprehensive review of its options using a capacity expansion model that would test the AOGP against optimized portfolios that could achieve the same benefits as the AOGP with a different set of resources. However, PREPA still requires a clearly defined plan to obtaining all necessary permits as well as a potential partner to construct the AOGP. With Excelerate's cancellation of contracts in July 2017, and FERC's Order Vacating Authorization of January 28, 2019, vacating FERC's 2015 authorization, PREPA would need to solicit renewed interest in the project from potential partners.

7.1.2.8 Ship-based LNG (or CNG) at San Juan with Possible Pipeline to Palo Seco

PREPA has studied a ship-based standard-scale LNG (and CNG) receiving terminal in the San Juan area, including a ship-based (offshore) option known as a floating storage and regasification unit (FSRU). A June 2015 Galway Energy Advisors natural gas study for PREPA's northern power plants (San Juan and Palo Seco) evaluated the feasibility and potential fatal flaws of an import facility sized to handle 125,000 MMBtu per day. The study looked at importing either LNG or CNG. Given the lack of CNG project examples in the U.S. and PREPA's preference for 1-2 deliveries per month to limit traffic in the already busy San Juan port, the fuel choice of the higher volume CNG was evaluated but was considered less viable than LNG supplied via standard scale LNG ships delivering 2.0-3.6 million MMBtu per ship.

The Galway study considered one ship-based (offshore) and three land-based (onshore) options with 14 configurations, including an LNG regasification barge, an LNG FSRU, an LNG floating storage unit (FSU) with onshore vaporization, LNG and CNG onshore storage and vaporization, and non-self-propelled vessels with onboard CNG storage. All of the four site options would require one or more pipelines to deliver vaporized LNG or depressurized CNG to the power plants. Several considerations were weighed for a ship-based LNG terminal. Concerns identified with this option included potential harm to environmentally sensitive zones where coral reefs, mangroves, sea grass beds, wetlands, critical wildlife areas, rivers and streams, karst areas, and aquifers exist. In addition, harbor view impacts were considered, wherein the visual impact on residents was assessed. In general, an FSRU would be sited approximately three miles offshore, but would need to be sited 13 miles or

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[51] http://energia.pr.gov/wp-content/uploads/2017/05/PREPA-Ex-1.02-Part-1-Economic-Analysis-Report.pdf

more offshore to be completely out of sight of harbor residents. A location 13 miles offshore would require a lengthy pipeline, with its own environmental risks and added costs, to bring supply to the plants. The analysis reached the conclusion that among the 14 options, the most feasible option would be land-based (onshore) LNG storage and vaporization at a warehouse site adjacent to the San Juan power station and with standard scale LNG carrier delivery directly to onshore tanks.

A separate 2018 study[52] evaluated the economics of land-based (onshore) LNG storage and vaporization and compared to FSRU receiving terminals through the assessment of analyses performed for Indonesia, an island nation best served by LNG. An FSRU terminal in Sorong, Indonesia was estimated to be $0.6 million per MMcf/d in capital costs versus $2.1 million per MMcf/d for a land-based option. The FSRU vs. land-based (onshore) LNG produced an internal rate of return (IRR) of 13.77% vs. -0.27%, respectively, with the principle difference in IRR due to the difference in the 3.5:1 capital cost ratio. The study affirmed the use of a $4.35 per MMBtu transportation adder (liquefaction + transportation + margin) for LNG from the Gulf Coast, Trinidad & Tobago, or other nearby source. However, differences in volume and location-based costs exist between the Indonesian example and San Juan port, and this rule-of-thumb estimate predicts a lower capital cost estimate for the FSRU. A different 2017 study[53] estimated the cost for a new 30,000 m^2 LNG tanker at $105 million, which is the Exhibit used in this analysis (together with an additional $80 million in costs for regasification, jetty, piping, etc.). It is possible to reduce the capital cost for an FSRU by the utilization of a used LNG tanker, which could also reduce, by up to half, the time to implement the FSRU project. A September 2018 announcement by TEMA LNG Terminal Co Ltd[54] puts the cost of an estimated small-scale 20,000 m^2 FSU based in Ghana at $350 million with an 18 month project timeframe. In any event, the FSRU option is expected to remain the lower cost option vs. land-based LNG to meet the fuel needs of San Juan and Palo Seco plants. The FSRU option comes with the added benefit that it could potentially be repurposed, and the terminal moved or sold to recover some of the initial capital investment.

New Fortress Energy was the winning proponent to a competitive RFP issued by PREPA in 2018 for a supply of LNG for the San Juan Power Plant. NFE and PREPA executed a contract to sell LNG to PREPA under a 5-year contract and convert San Juan units 5 and 6 to burn natural gas. The delivered LNG price is tied to Henry Hub with an adder, and the contract has no long-term commitment or upfront capital cost commitment. The capital investment would be recovered through a calculated gas adder to the rate. The NFE project is currently under construction, and PREPA is pursuing regulatory authorizations to convert the San Juan 5 and 6 Units to be dual fuel capable.

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[52] "An Economic Evaluation of Onshore and Floating Liquefied Natural Gas Receiving Terminals: the Case Study of Indonesia," Giranza and Bergmann (2018), http://iopscience.iop.org/article/10.1088/1755-1315/150/1/012026/pdf

[53] "Small Scale LNG: Emerging Technologies for Small-Scale Grids," Tony Regan, DataFusion Associates, http://esi.nus.edu.sg/docs/default-source/doc/smallscale-lng---esi-roundtable.pdf?sfvrsn=2&_sm_au_=iVVVtq5FtZNFJDTM

[54] Jiangnan to build regas barge for Ghana's first LNG import project, Mike Corkhill, LNG Shipping World, https://www.lngworldshipping.com/news/view,jiangnan-to-build-regas-barge-for-ghanas-first-lng-import-project_54246.htm

Trinidad & Tobago is the primary supplier of LNG to Puerto Rico and since 2010 has shipped an average of 2.1 Bcf/month of natural gas to EcoEléctrica Inc. as well as additional LNG (since 2012) to Costa Sur via the same EcoEléctrica LNG Import Terminal.

Ship-based LNG delivery to the San Juan region with ship-based or onshore LNG storage and vaporization is a viable fuel infrastructure option for PREPA. However, the most likely Scenario is a medium-scale LNG ship (30,000 m^2 – 60,000 m^2) rather than a large-scale LNG carrier (85,000 m^3 to 170,000 m^3 or more), which would require dredging large quantities of material from the San Juan harbor to create a channel suitable for the large-scale LNG carriers. The potential benefits of the option for medium-scale LNG carriers (with regasification either floating or land-based) include efficient delivery of cost-competitive bulk LNG with minimal impact from increased ship traffic, reduced carbon emissions by converting units at San Juan and Palo Seco to natural gas from residual fuel oil, and lower fuel costs compared to current infrastructure in either a base case price or a high oil price Scenario. Possible risks include a sustained low-oil price future rendering operating costs higher using natural gas than residual fuel oil, the creation of new fuel infrastructure that could be vulnerable to hurricanes, supply chain vulnerability preventing timely delivery of LNG, and the possibility of a decreasing need for fossil generation as load decreases with further population out-migration or as PREPA increases energy efficiency programs and renewable energy penetration.

Onshore LNG storage offers advantages and disadvantage compared to ship-based offshore storage (FSU) and/or regasification (FSRU) or regasification. The FSU and FSRU options may require authorization from the Federal Energy Regulatory Commission (FERC), the U.S. EPA, the U.S. Department of Transportation Maritime Administration, the U.S. Coast Guard, local agencies in Puerto Rico.. Furthermore, several existing statutes would need to be navigated, including the Natural Gas Act, the Clean Air Act, the Clean Water Act, the Deepwater Port Act, the National Environmental Policy Act, the Comprehensive Environmental Response, Compensation, and Liability Act, the Maritime Protection, Research, and Sanctuaries Act, the Resource Conservation and Recovery Act, the Rivers and Harbors Act, and others.55 All offshore pipelines would require a subsea pipeline to both San Juan and Palo Seco power plants. By contrast, the onshore LNG storage option would be co-located by the San Juan plant with a connecting pipeline to Palo Seco. This onshore option would avoid some of the regulatory requirements mentioned above with the FSU and FSRU options but would be subject to its own regulatory challenges. The onshore LNG storage and FSU/FSRU options would need to consider land use and/or port lease issues as well as infrastructure buildouts.

A ship-based FSRU could occupy one of two berths directly in front of the San Juan steam plant. Based on an estimated 400 MW gas-fired capacity at San Juan, the maximum daily gas volume requirement would not exceed 50.4 MMcf/d. However, if a pipeline to the Palo Seco plant is included, adding an incremental 302 MW of gas-fired capacity at Palo Seco, the maximum daily gas volume requirement would increase to 93.6 MMcf/d. The extant remaining regasifier (93 MMcf/d send-out capacity) at the EcoEléctrica LNG Import Terminal could satisfy these needs if a pipeline were to be built from the import terminal to the north, either directly or routed via Aguirre.

[55] https://www.epa.gov/sites/production/files/2015-08/documents/lng_regulatory_roadmap.pdf

7.1.2.9 Land-based (onshore) LNG at San Juan with pipeline to Palo Seco

As mentioned previously, the Galway study reached the conclusion that among the 14 options, the most feasible is land-based (onshore) LNG storage and vaporization at a warehouse site adjacent to San Juan power station on its east side and with standards scale LNG carrier delivery directly to onshore tanks. The best option considered was immediately adjacent to San Juan plant in a warehouse district to the east. A second viable option for an onshore storage and vaporization system was considered further to the east of San Juan plant at a location known as Pier 15/16. However, Siemens notes that an onshore facility is likely to be costlier than an FSRU or FSU option. Furthermore, the Galway study did not consider small- to medium-scale LNG carriers as a possible supply option for direct delivery into San Juan harbor. Instead the Galway study considered smaller-scale shuttle tankers being loaded from LNG ships via ship-to-ship transfer in the area of Guayanilla Canyon on the protected south side of Puerto Rico).

Looking at the generation plants that an onshore LNG terminal would supply, it is expected that current generating units using residual fuel oil at San Juan and Palo Seco will be replaced, retired or limited in use in several years to achieve MATS compliance. The replacement generation for these sites will be capable of natural gas and diesel firing. A northern LNG terminal could provide significant cost savings relative to diesel fuel. Based on input from PREPA, a land-based (onshore) LNG terminal at San Juan would require an estimated $492 million in capital costs (2018$) including $457 million for the LNG terminal and $35 million for the pipeline from San Juan to Palo Seco. Note that the pipeline costs are lower than in the 2015 IRP due to the assumed use of an existing oil pipeline right-of-way to construct the 4.2 mile pipeline to Palo Seco. Annual fixed operating costs (OPEX) are conservatively assumed to be 5.2% of total capital expenditures (CAPEX), whereas the general rule of thumb for OPEX is 2.5%-3% of CAPEX. The earliest online date would be July 1, 2023.

7.1.2.10 Ship-Based LNG to Mayagüez (west) and/or Yabucoa (east)

Mayagüez is located on the western side of the island, where PREPA has a 4x50 MW (total of 200 MW) diesel-fired generation. Yabucoa is located on the eastern side of the island, where PREPA has two combustion turbines (2x21 MW) also burning diesel. Siemens is investigating the possibility of one or more floating LNG and storage import terminals that could service the power generation plants at Mayagüez, Yabucoa, or both locations. The existing generation could be complemented with up to 302 MW of gas-fired generation, which would require a natural gas fuel supply solution. The proposed solution would most likely be a ship-based (offshore) FSRU option, similar to what could be installed in the San Juan port for LNG supply to San Juan plant and/or Palo Seco plant and with similar capital expenditure and operating expenditure estimates. Accordingly, Siemens estimates the CAPEX for ship-based LNG delivery to Mayagüez and/or Yabucoa to be $185 million and the annual OPEX to be $9.6 million.

7.1.2.11 LNG/CNG Delivery via ISO Containers to Northern Power Plants

Alternatively, natural gas supply to the northern side of the island could be delivered in the form of LNG or CNG using ISO containers. This mode of LNG or CNG transport uses standard, intermodal, 40 foot ISO containers that can be marine-shipped, trucked, handled, and stored much like a standard 40 foot cargo container. Each 40 foot LNG ISO container is

an independent storage system with about an 858 MMBtu capacity for up to a 90 day storage period. Each 40 foot CNG ISO container has a capacity of about 267 MMBtu.

There are numerous LNG and CNG suppliers available in the U.S. and internationally that utilize these systems. LNG and CNG ISO containers potentially could be delivered to the San Juan port and unloaded using standard container handling equipment, trucked to San Juan / Palo Seco sites using existing container tractor-trailers, and then directly connected to a common regasification system feeding the fuel delivery piping of individual units. While this delivery method is generally more costly than bulk supply for large volumes of LNG, it could be a cost-effective option to fuel the new small CCs at Palo Seco. In addition, the LNG or CNG ISO containers could provide an interim solution that could deliver fuel to the San Juan Units 5 and 6 CCs while long-term delivery infrastructure is being permitted and constructed.

The San Juan port that is directly adjacent to the San Juan power plant has a large capacity container terminal that could potentially support daily full and empty LNG container movements. About 50 of these containers per day could be loaded onto trucks for transport to Palo Seco, with empty containers carried back on the return trip. LNG or CNG containers[56] also could be used to deliver natural gas to peaking sites such as Cambalache and Mayagüez. The practicality of delivering the large volume of LNG or especially CNG required for both Palo Seco CCs and San Juan CCs has been assessed.

The same March 2017 Siemens PTI fuel delivery assessment further developed this analysis of LNG / CNG to northern power plants and separately to Aguirre, estimating that containerized LNG deliveries would require 40 ISO containers per day while CNG deliveries would require 126 containers per day to meet project demand at the two northern power plants (for Aguirre, it would be 193 and 617 containers, respectively). As a result, the study concluded that small-scale LNG / CNG delivery either as a bridge fuel or long-term solution is not feasible given that small-scale LNG / CNG delivery costs to San Juan are prohibitively high and operational risks are too great. The study recommended further evaluation of bulk LNG delivery to San Juan and Palo Seco with onsite tank storage (the same conclusion as the previously cited Galway study). Siemens does not recommend small-scale LNG or CNG delivered via ISO containers as a viable solution for this IRP.

7.1.2.12 Pipeline Supply from EcoEléctrica LNG Import Terminal

An alternative to a northern LNG / CNG terminal and potentially also to the AOGP could be a natural gas pipeline that delivers natural gas from the existing EcoEléctrica LNG Import Terminal to the San Juan and Palo Seco plants in San Juan. Such a pipeline could be constructed to have one segment along the southern coast of Puerto Rico to serve the Aguirre power plant (creating an alternative to the AOGP plant) before a second segment turns north toward the San Juan plant with a lateral to Palo Seco. Alternatively, a pipeline could be routed to go directly from the EcoEléctrica LNG Import Terminal to San Juan, which would not require additional regasification apart from bringing online the extant remaining gasifier. Any such project must consider the pipelines costs as well as permitting feasibility.

[56] LNG tank trailers also can be used to transport LNG. With necessary permitting and commercial arrangements, trailer loading facilities could be located at any site with bulk LNG storage, such as EcoEléctrica, or at an onshore LNG terminal at San Juan.

A past 2008n proposal to bring natural gas to the north (Gasoducto del Norte or GdN, also known as Via Verde) by pipeline from EcoEléctrica LNG Import Terminal encountered significant public opposition during permitting and was canceled. Several pipeline routes were considered but the option designated as preferred was generally north from EcoEléctrica to Arecibo and then east to Palo Seco/San Juan. Laterals were considered to serve the Cambalache and Mayagüez peaking units. A South-North pipeline from Aguirre to San Juan area could be more practical than the preferred western routes considered earlier. A natural gas pipeline between Costa Sur and Aguirre has been attempted in the past (Gasoducto del Sur) and is technically feasible. Section 2.6.1 of the 2008 GdN study referenced above identified two possible routes from Aguirre to the north. These routes' lengths were about 50 miles each, with about 600 acres of right-of-way including up to 64 acres of wetlands impact. One of these routes is close to an already-disturbed corridor for Route 52 and had the lower wetlands impact. A pipeline route along the south coast, from Costa Sur to Aguirre, generally is perceived as more practical and having less environmental and public impact than a pipeline along the northern coast. This portion of a system to transport natural gas from EcoEléctrica to the north may be less controversial than the South-North section.

The 2008 GdN report provided estimated costs for such a pipeline, confirmed by more recent estimates performed by Siemens. The Aguirre-San Juan overland route (not the route along Route 52) was about 52 miles long before adjustment for terrain. A 20 inch pipeline size was assumed for a flow volume of 249 MMcf/d. Costs included route surveying, engineering, project management, inspection, materials, construction and restoration. The cost of this line in mid-2008 U.S. dollars was $206 million, or $238 million in 2018 dollars. This comports well with Siemens' current estimate of a cost of $221 million for this South-North pipeline route, although Siemens estimated that a 16" pipe is sufficient to supply the combined 93.6 MMcf/d demand from San Juan and Palo Seco after conversion to natural gas. Other assumptions used by Siemens include a distance of 49 miles and $4.5 million per mile (2018$). Considering that a south coast pipeline (Costa Sur to Aguirre) has been budgeted in the past, PREPA should have reasonably accurate estimates of cost. The pipeline nominal length from Costa Sur to Aguirre is 42 miles. Using a cost of about $5.1 million per mile (2018$) for 20" pipeline, which would carry 249 MMcf/d or sufficient gas volumes to supply Aguirre, San Juan and Palo Seco, this would cost approximately $214 million. The total cost for a pipeline from EcoEléctrica LNG Import Terminal to Aguirre to San Juan is estimated to be $470 million, including $35 million for a short 4.2 mile pipeline to the Palo Seco plant.

Although a pipeline route has been attempted in the past, but was halted due to public opposition, the aftermath of the storms represents an important inflection point in Puerto Rico's history. There is a potential window of opportunity to re-evaluate the pipeline option during this time of rebuilding. It is recommended that an updated cost and routing analysis be conducted on possible pipeline supply options to Aguirre and San Juan/Palo Seco.

7.1.2.13 Alternative Fuels

PREPA received an unsolicited proposal from Puma Energy Caribe (Puma) and Aggreko in August 2017, which was approved for further consideration in October 2017. The proposal was for a 100 MW power generation solution using LPG (liquefied petroleum gas, which is mostly propane) in Bayamón, Puerto Rico (just outside of San Juan). The proposal would satisfy several important criteria that PREPA is looking for in power generation solutions, including a location in the north near load centers, a public/private partnership (P3) that would require no capital expenditure from PREPA and conforms to PREPA's Fiscal Plan Part VII (Investment Program) requiring that P3 generation in year 2026 be approximately 30% of the

total system generation, and a turnkey approach that can be implemented quickly. The proposed solution would also have a relatively low heat rate (8,900 Btu/kWh) to provide efficient power generation, burn relatively clean LPG fuel to help meet MATS standards (and which is typically cheaper than diesel or residual fuel oil), have a fast start time of two minutes to 100% capacity, and be strategically located near existing Puma facilities where no additional LPG storage would be needed beyond the existing 100,000 barrels of LPG storage.

Siemens believes that LPG fuel will remain cost-competitive compared to diesel and residual fuel oil. This aspect, together with the other attributed enumerated above, lead to the conclusion that this project is worthy of further exploration as one solution among many to develop new sources of power generation. The PUMA proposal that Siemens reviewed did not include a pricing formula or forecast, so an LPG price forecast was developed using the historical price relationship with crude oil. This forecast is provided in the following forecast section.

A coal price forecast is also provided for fuel supply costs to the AES plant, based on Siemens' 2018 spring outlook and benchmarked to the EIA AEO 2018 forecast and others.

7.1.2.14 No New Natural Gas Infrastructure

If additional natural gas infrastructure and supplies cannot be developed, one option is to maintain the status quo. This option ignores the potential fuel cost savings that could come from natural gas supply and may also increase the challenges with meeting MATS requirements. This option should also be considered in the IRP planning process, pending the available generation options review.

Other potential liquid fuels such as propane, ethane and biofuels could be considered. Over the past two years, propane has been about 2.5 times as costly as natural gas on an equivalent MMBtu basis. Propane when burned for power generation emits about 16% more carbon dioxide than natural gas but is cleaner than residual fuel oil. While increases in propane and ethane production associated with U.S. shale gas production have led to recent market imbalances that have depressed the prices of these products, prices have begun to rise again as the market recovers. Siemens believes that in the long-term, propane and ethane prices will maintain higher levels relative to diesel and certainly with respect to natural gas. So, while there may be some interim opportunities to take advantage of such fuels, propane, ethane, and biofuels are not expected to be long-term cost-effective solutions.

7.1.2.15 Fuel Infrastructure Scenarios Comparison

As discussed previously, there are a broad range of fuel infrastructure Scenarios. These include the following, in no particular order:

- Aguirre Offshore Gas Port (AOGP)
- Land-based (onshore) LNG to the North
- Ship-based (offshore) LNG to the North
- Ship-based (offshore) LNG at Mayagüez (west)
- Ship-based (offshore) LNG at Yabucoa (east)
- Small-scale LNG and CNG to the North and South

- Additional Regasification Capacity at EcoEléctrica LNG Import Terminal with a Costa Sur-Aguirre-San Juan Pipeline
- No New Gas Infrastructure

Each fuel infrastructure Scenario should be evaluated, at a minimum, on the broad categories of capital cost requirements, estimated operational costs, resiliency and reliability, environmental impact, and public concerns. Many other considerations are embedded within these categories, including technical complexity, permitting process, fuel supply options, regulatory compliance, commercial partnerships, etc. The following table provides a summary evaluation of these infrastructure options.

Exhibit 7-4. Fuel Infrastructure Options Assessment

Infrastructure Option	CAPEX ($MM) (2018$)	Annual OPEX ($MM) (2018$)	Max Daily Gas Volume (MMcf/d)	Max Capacity (MW)	Annualized CAPEX ($/kW) (2018$)	Annual OPEX ($/kW) (2018$)
Aguirre Offshore GasPort	GasPort=$403 - Annual O&M=$81.5 (+fuel)	(1,076 MW) - (7,500 Btu/kWh) - 155 MMcf/d	Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to AOGP or south-to-north power transmission.	Carbon and other emissions would be reduced with AOGP and conversion at Aguirre to gas-fired generation.	Infrastructure would be located away from population but concerns over cost and stranded fossil fuel plant.	N/A
Ship-based LNG (FSRU) at San Juan Port with pipeline to both plants	FSRU=$185 - Pipeline to Palo Seco=$35 - Annual O&M=$11.4 (+fuel)	(650 MW) - (7,500 Btu/kWh) - 93.6 MMcf/d	Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to FSRU.	Carbon and other emissions would be reduced with FSRU and gas-fired generation. Increased vessel traffic could impact coastal marine life.	Harborview would be impacted by FSRU and potential damage to marine environment from pipeline.	N/A
Ship-based LNG at Mayagüez (west)	FSRU=$185 - Annual O&M=$9.6 (+fuel)	(300 MW) - (7,500 Btu/kWh) - 43.2 MMcf/d	Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to FSRU.	Carbon and other emissions would be reduced with FSRU and gas-fired generation. Increased vessel traffic could impact coastal marine life.	Infrastructure would be located away from population but concerns over cost and stranded fossil fuel plant.	N/A
Ship-based LNG at Yabucoa (east)	FSRU=$185 - Annual O&M=$9.6 (+fuel)	(300 MW) - (7,500 Btu/kWh) - 43.2 MMcf/d	Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to FSRU.	Carbon and other emissions would be reduced with FSRU and gas-fired generation. Increased vessel traffic could impact coastal marine life.	Infrastructure would be located away from population but concerns over cost and stranded fossil fuel plant.	N/A

Infrastructure Option	CAPEX ($MM) (2018$)	Annual OPEX ($MM) (2018$)	Max Daily Gas Volume (MMcf/d)	Max Capacity (MW)	Annualized CAPEX ($/kW) (2018$)	Annual OPEX ($/kW) (2018$)
Small-scale LNG (or CNG) Solutions at San Juan Port and/or Aguirre	CAPEX=$540 - Annual O&M= $45-81	50-249 MMcf/d	Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to small-scale LNG port.	Carbon and other emissions would be reduced with LNG. Increased vessel traffic could impact coastal marine life.	Concerns over significantly increased vessel traffic in busy ports and potential damage to marine environment.	Unfeasible logistics for large volume customers
Land-based LNG at San Juan Port with pipeline to Palo Seco	Onshore LNG Terminal=$457 - Pipeline=$35 - Annual O&M=$25.6	93.6 MMcf/d	Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to onshore LNG port.	Carbon and other emissions would be reduced with LNG. Increased vessel traffic could impact coastal marine life.	Concerns over significantly increased vessel traffic, disruptive pipeline to Palo Seco.	N/A
Pipeline from Costa Sur to Aguirre and San Juan (with additional regasification at EcoEléctrica)	Costa Sur to Aguirre Pipe=$184 - Aguirre to San Juan Pipe=$238 - Annual O&M=$40	249 MMcf/d	Resiliency and reliability increased by transport via underground pipeline, providing flexibility to burn gas or diesel at converted generation plants. Additional regas capacity provided by private co.	Carbon and other emissions would be reduced with pipeline gas delivery and conversion to gas-fired generation.	Previous attempt to construct Costa Sur to San Juan pipeline was cancelled due to public concerns.	N/A
No New Gas Infrastructure	N/A	N/A	Existing generation plants lack flexibility in cleaner fuel choice. Onsite fuel storage more reliable than LNG deliveries susceptible to disruption.	Carbon and other emissions would remain higher than permissible/desired under current regulations.	Leaves space for increased renewables penetration and removes risk of stranded fossil fuel assets.	N/A

Source: Siemens, PREPA.

For the purposes of this 2018 IRP, there are four key fuel infrastructure options under consideration, which include:

- The land-based LNG at San Juan Port with pipeline to Palo Seco
- The ship-based LNG at Mayagüez (west),
- The ship-based LNG at Yabucoa (east), and
- The ship-based LNG (FSRU) at San Juan Port (supply to San Juan only).

Exhibit 7-5 below provides a summary view of these four infrastructure options together with CAPEX (2018$MM), annual OPEX (2018$MM), maximum daily gas volumes (MMcf/d), maximum generation capacity (MW), CAPEX in $/kW, and annual OPEX in $/kW.

Exhibit 7-5. Fuel Infrastructure Options Assessment

Infrastructure Option	CAPEX ($MM) (2018$)	Annual OPEX ($MM) (2018$)	Max Daily Gas Volume (MMcf/d)	Max Capacity (MW)	Annualized CAPEX ($/kW) (2018$)	Annual OPEX ($/kW) (2018$)	CAPEX + Annual OPEX ($/kW) (2018$)
Land-based LNG at San Juan Port with pipeline to Palo Seco	$492	$25.6	93.6	650	$77	$39	$117
Land-Based San Juan Low CAPEX Estimate	$408	$21.2	93.6	650	$64	$33	$97
Land-Based San Juan High CAPEX Estimate	$590	$30.7	93.6	650	$93	$47	$140
Ship-based LNG at Mayagüez (west)	$185	$9.6	43.2	300	$63	$32	$95
Ship-based LNG at Yabucoa (east)	$185	$9.6	43.2	300	$63	$32	$95
Ship-based Mayagüez-Yabucoa Low CAPEX Estimate	$167	$8.7	43.2	300	$57	$29	$85
Ship-based Mayagüez-Yabucoa High CAPEX Estimate	$222	$11.5	43.2	300	$75	$38	$114
Ship-based LNG (FSRU) at San Juan Port (supply to San Juan only)	$185	$9.6	50.4	350	$54	$27	$81
Ship-based San Juan Low CAPEX Estimate	$167	$8.7	50.4	350	$48	$25	$73
Ship-based San Juan High CAPEX Estimate	$222	$11.5	50.4	350	$65	$33	$98

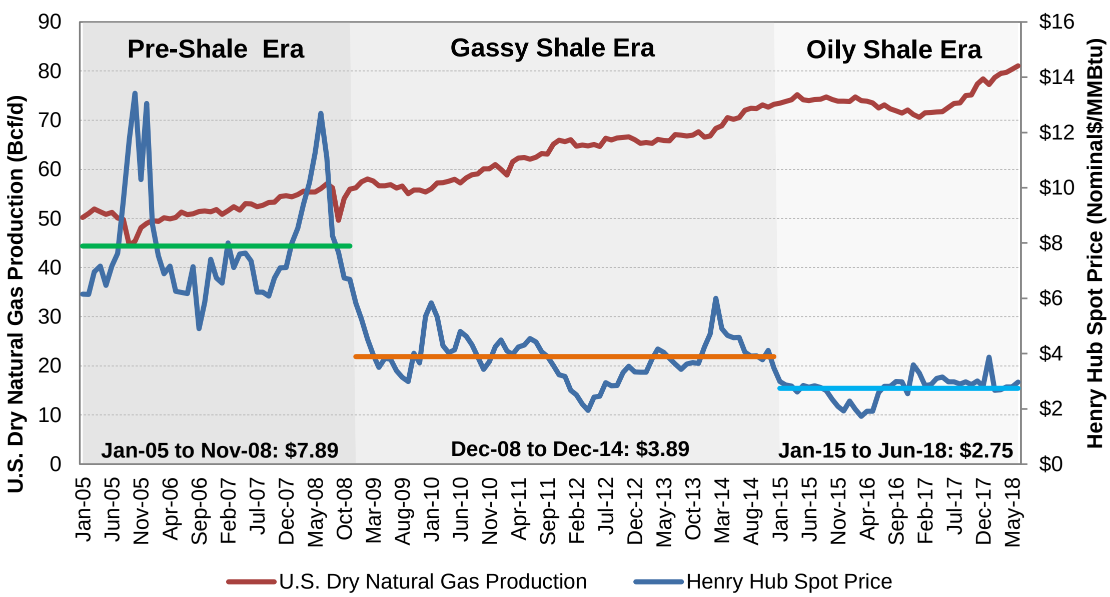
Apart from the No New Gas Infrastructure Scenario, the ship-based LNG (FSRU) at San Juan Port Scenario represents the lowest CAPEX and annual OPEX cost. The three feasible LNG to the North Scenarios (ship-based LNG, land-based LNG, and pipeline) would support the conversion of the northern plants of San Juan and Palo Seco (currently 1,158 MW) to natural gas, but with very different CAPEX costs depending upon the infrastructure. Ship-based LNG (FSRU) would be the least-cost, followed by pipeline supply from the south, followed by land-based LNG. The Costa Sur to Aguirre to San Juan Pipeline Scenario envisions the broader conversion to natural gas of generation plants at Aguirre, San Juan, and Palo Seco with commensurate benefits in terms of lower emissions and lower fuel costs than existing generation. The pipeline Scenario would also require upgrades to the EcoEléctrica LNG Import Terminal to supply sufficient fuel to meet this increased demand, but the costs would be borne by the private EcoEléctrica company. Each of these fuel infrastructure Scenarios bears merit and also has drawbacks that must be weighed in the context of the larger IRP study. Accordingly, a recommendation for pursuing one of these Scenarios is reserved pending the completion of the comprehensive review of PREPA's options using a capacity expansion model that would assess the convenience of installing natural gas generation or converting exiting units as is the case of San Juan 5 & 6 against optimized portfolios that could achieve similar benefits with different sets of resources.

7.2 Fuel Price Forecasts

Siemens prepared fuel price forecasts for natural gas at the Henry Hub, crude oil (West Texas Intermediate or WTI), and the oil-derivate products of diesel (No. 2 fuel oil) and residual fuel oil (No. 6 fuel oil with 0.5% sulfur). The Henry Hub benchmark is located in Erath, LA while the WTI benchmark is located in Cushing, OK. The diesel and residual fuel oil forecasts are based on New York Harbor pricing (per the contract terms for Costa Sur). The following sections describe the methodology for preparing these commodity forecasts for the 2018 IRP. Although standard scale LNG deliveries from the mainland U.S. would be difficult under the restrictions of the Jones Act, the following forecasts nevertheless are based on Henry Hub pricing to align with current fuel supply contract terms.

In accordance with the recommendation of the Transformation Advisory Council (TAC), which advocated for the use of a 10-year implied market volatility assumption for oil and natural gas in lieu of the 3-year volatility assumptions used in Siemens' original stochastic price simulations, Siemens has taken into consideration the recommendation for oil price volatility. However, for natural gas price volatility, Siemens feels there is justification for a shorter historical lookback. The pricing graph in Exhibit 7-6 shows how natural gas prices have declined in each of two different shale eras. Price volatility has also declined along with absolute prices. A potential return to higher price oil, which 2018 experienced for nearly the whole year, would help to increase associated gas production and keep additional downward price pressure on natural gas.

Exhibit 7-6. Pricing Eras of the Shale Revolution



Sources: Siemens, EIA.

By contrast with natural gas, which is still a regional market, oil is much more a global commodity and its price and volatility have been less affected by U.S. oil shale production than U.S. shale gas. This is an argument for a longer historical lookback when calculating the implied market volatility of oil, so Siemens took the TAC recommendation and recalculated the price distributions using a 10-year implied market volatility assumption. This allowed for

the comparison of the 10-year, 5-year, and 3-year implied market volatility, which are 2.04%, 1.85%, and 1.83%, respectively. The result of the 10-year update was a higher short-term outlook but relatively unchanged long-term outlook at the one standard deviation level (84.1st percentile band). Although it is exceedingly rare as a Scenario, Siemens uses the two standard deviation level (97.7th percentile band) as a high oil price boundary case, which represents a future in which in only 23 out of 1,000 cases will have higher oil prices. This would see oil prices reach $190/bbl in nominal dollars by the end of the forecast.

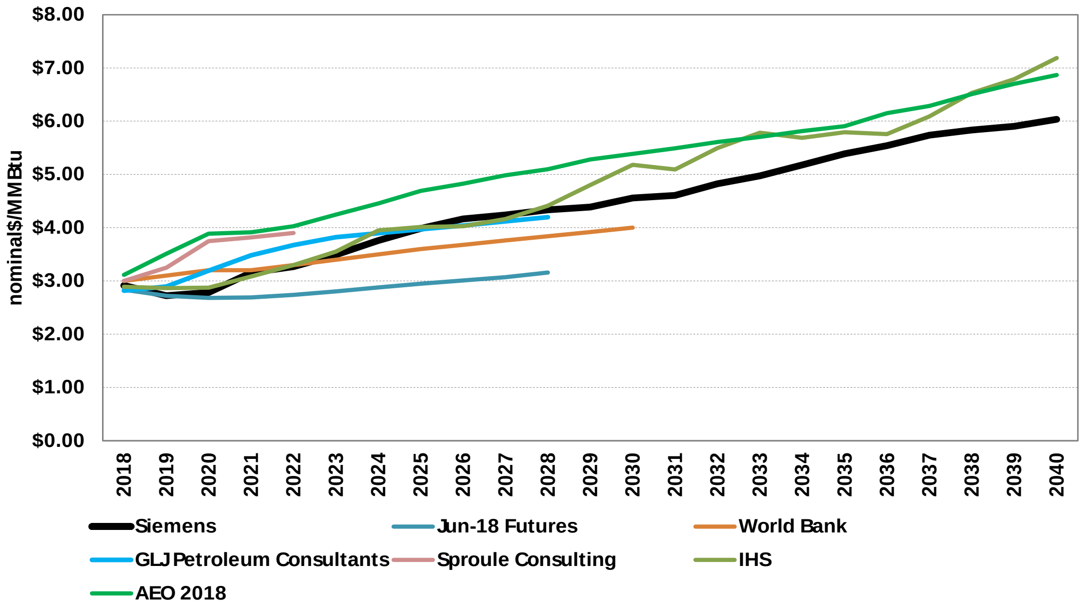
7.2.1 Henry Hub Natural Gas

Siemens develops an independent projection of regional fuel prices, in particular natural gas, crude oil and its derivative products (diesel, fuel oil, LPG, etc.). The natural gas price projections are developed using the GPCM® tool, is described in more detail in the Attachment A, includes the benchmark Henry Hub price hub as well as more than 60 liquid trading hubs across North America. Siemens's Henry Hub forecast incorporates updated assumptions for natural gas demand, supply, and infrastructure and also benchmarks its short-term natural gas forecast to recent market forwards. Forwards are dated from June 2018. These forwards were used explicitly for the first 18 months of the forecast (June-2018 to Nov-2019), then blended into the fundamental forecast over the following 18 months. The first three years of the forwards curve represent the most liquid part of the curve, when trades and volumes are significantly higher than afterward. Exhibit 7-7 below provides a comparison of Siemens' forecast for Henry Hub prices with the AEO 2018 Henry Hub forecast as well as several other forecasts, for reference.

Exhibit 7-7. Henry Hub Forecast Comparison (nominal$/MMBtu)

Forecaster	Siemens	AEO 2018	Jun-18 Futures	World Bank	GLJ Petroleum Consultants	Sproule Consulting	IHS
Unit	nom$/ MMBtu	nom$/ MMBtu	nom$/ MMBtu	nom$/ MMBtu	nom$/ MMBtu	nom$/ MMBtu	nom$/ MMBtu
Date	Jun-18	Feb-18	Jun-18	Apr-18	Apr-18	May-18	Feb-18
2018	2.91	3.11	2.84	3.00	2.82	3.00	2.89
2019	2.72	3.51	2.72	3.10	2.90	3.25	2.87
2020	2.79	3.89	2.68	3.20	3.20	3.75	2.88
2021	3.16	3.92	2.69	3.20	3.48	3.82	3.09
2022	3.27	4.03	2.74	3.30	3.67	3.90	3.30
2023	3.49	4.25	2.81	3.40	3.82		3.55
2024	3.76	4.46	2.88	3.50	3.90		3.95
2025	3.98	4.69	2.95	3.60	3.97		4.01
2026	4.16	4.83	3.01	3.68	4.04		4.03
2027	4.24	4.98	3.07	3.76	4.12		4.16
2028	4.34	5.10	3.16	3.84	4.20		4.41
2029	4.39	5.28		3.92			4.80
2030	4.56	5.39		4.00			5.18
2031	4.61	5.49					5.09
2032	4.82	5.61					5.50
2033	4.97	5.71					5.78
2034	5.18	5.81					5.69
2035	5.39	5.91					5.79
2036	5.54	6.15					5.76

Forecaster	Siemens	AEO 2018	Jun-18 Futures	World Bank	GLJ Petroleum Consultants	Sproule Consulting	IHS
Unit	nom$/ MMBtu	nom$/ MMBtu	nom$/ MMBtu	nom$/ MMBtu	nom$/ MMBtu	nom$/ MMBtu	nom$/ MMBtu
Date	Jun-18	Feb-18	Jun-18	Apr-18	Apr-18	May-18	Feb-18
2037	5.74	6.29					6.09
2038	5.84	6.51					6.53
2039	5.90	6.70					6.79
2040	6.03	6.87					7.19



Source: Siemens, various sources.

Siemens prepared a delivered natural gas price forecast for the Costa Sur, San Juan, and Aguirre generation plants, as well as the Mayagüez and Yabucoa plants, each of which can or could receive natural gas as a fuel supply and which represent the four sides of the island. In the case of Costa Sur, which is currently under a fuel supply contract[57], the adders are already known and applied to derive a delivered natural gas forecast price. In the case of Aguirre and San Juan, a pricing formula equal to 115% of Henry Hub plus $4.35/MMBtu was used, which reflects a $2.80 adder for liquefaction, a $1.00 adder for transport, and a $0.55 adder for margin. The Mayagüez and Yabucoa plants are assumed to have a similar LNG price structure as San Juan.

7.2.2 EIA Annual Energy Outlook 2018

The U.S. Department of Energy's (DOE) EIA Annual Energy Outlook (AEO) 2018[58], issued February 2018, provides their latest forecast for natural gas prices at the benchmark Henry Hub based on the key fundamentals of supply, demand, and infrastructure. The AEO 2018

[57] http://energia.pr.gov/wp-content/uploads/2018/08/Memorial-Explicativo-R-del-S-219-CEPR.pdf

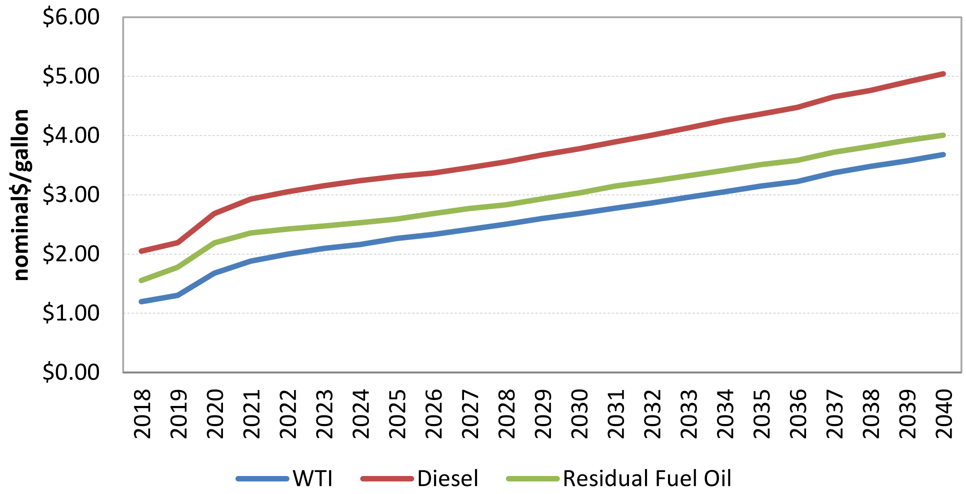
[58] https://www.eia.gov/outlooks/aeo/

Reference case forecasts that natural gas production growth will outpace consumption growth in every year to the forecast horizon of 2050. This driver, together with an estimated increase in lower-cost resources in the Permian and Appalachian basins, has resulted in Henry Hub prices that are 14% lower this year than last year's AEO. In the Permian basin, associated natural gas production from tight oil production is supported by relatively high oil prices. In the Appalachian basin, the Marcellus and Utica plays (located in Pennsylvania, Ohio, and West Virginia) continue to drive most U.S. production growth as they have over the last several years due to the substantial resource in-place with low production costs proximate to key demand centers in the U.S. Northeast. On the demand side, industrial and power generation demand together drive natural gas consumption growth to 2050. Growth in exports via liquefied natural gas (LNG) facilities is strong through 2030 and pipeline exports to Mexico through 2025.

The AEO 2018 forecast for WTI, distillate fuel oil (diesel), and residual fuel oil is provided in Exhibit 7-8 below.

Exhibit 7-8. AEO 2018 Price Outlook (nominal$/gallon)

Product	WTI	Diesel	RFO
Unit	nom$/ gallon	nom$/ gallon	nom$/ gallon
2018	1.20	2.05	1.56
2019	1.30	2.19	1.78
2020	1.68	2.68	2.18
2021	1.88	2.93	2.36
2022	2.00	3.05	2.42
2023	2.09	3.15	2.47
2024	2.16	3.24	2.53
2025	2.26	3.31	2.59
2026	2.33	3.37	2.68
2027	2.42	3.46	2.77
2028	2.50	3.55	2.83
2029	2.60	3.68	2.93
2030	2.68	3.77	3.03
2031	2.77	3.89	3.14
2032	2.86	4.00	3.23
2033	2.96	4.13	3.32
2034	3.05	4.26	3.41
2035	3.15	4.36	3.51
2036	3.23	4.47	3.58
2037	3.37	4.66	3.72
2038	3.48	4.76	3.81
2039	3.57	4.90	3.92
2040	3.68	5.04	4.01



Source: EIA

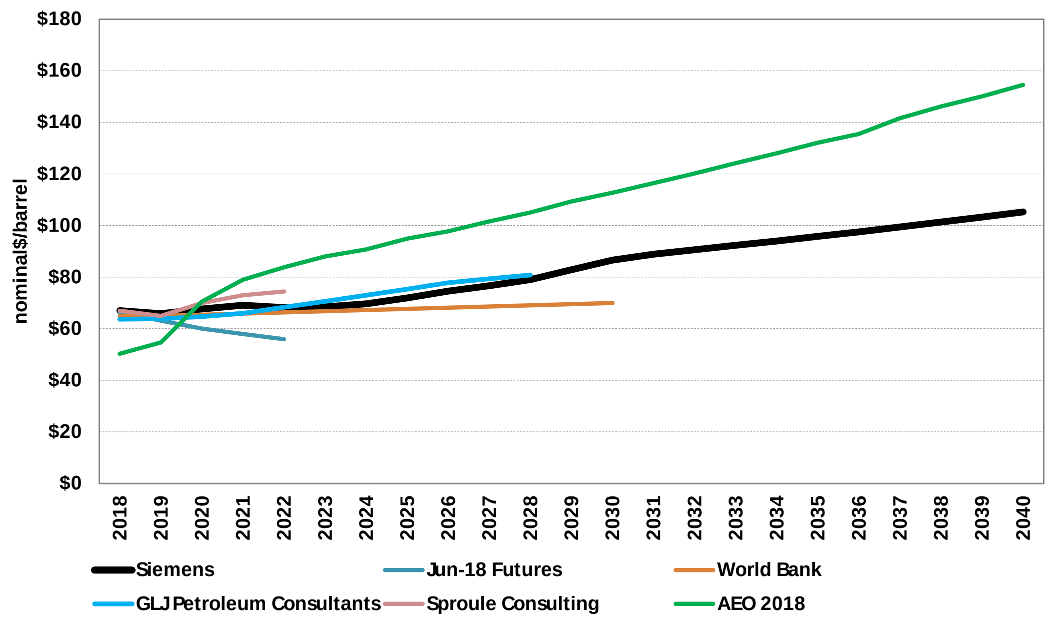
7.2.3 West Texas Intermediate (WTI) Crude Oil

Benchmark WTI oil price forecasts are developed exogenously by comparing and averaging price outlooks from a variety of reputable sources (EIA, IEA, etc.). A comparison of Siemens's WTI price outlook together with other outlooks is compiled in Exhibit 7-9.

Exhibit 7-9. WTI Forecast Comparison (nominal$/barrel)

Forecaster	Siemens	AEO 2018	Jun-18 Futures	World Bank	GLJ Petroleum Consultants	Sproule Consulting
Unit	**nom$/ barrel**	**nom$/ barrel**	**nom$/ barrel**	**nom$/ barrel**	**nom$/ barrel**	**nom$/ barrel**
Date	**Jun-18**	**Feb-18**	**Jun-18**	**Apr-18**	**Apr-18**	**May-18**
2018	67.02	50.31	66.31	65.00	63.67	67.00
2019	65.82	54.67	63.16	65.00	63.86	65.00
2020	67.65	70.48	59.99	65.40	64.69	70.00
2021	69.10	78.98	57.93	65.90	65.99	73.00
2022	68.20	83.85	55.98	66.30	68.33	74.46
2023	68.49	87.97		66.80	70.62	
2024	69.61	90.78		67.20	73.01	
2025	71.94	94.96		67.70	75.38	
2026	74.57	97.80		68.16	77.79	
2027	76.65	101.57		68.62	79.31	
2028	79.05	105.06		69.08	80.77	
2029	82.86	109.30		69.54		
2030	86.65	112.70		70.00		

Forecaster	Siemens	AEO 2018	Jun-18 Futures	World Bank	GLJ Petroleum Consultants	Sproule Consulting
Unit	nom$/ barrel	nom$/ barrel	nom$/ barrel	nom$/ barrel	nom$/ barrel	nom$/ barrel
Date	Jun-18	Feb-18	Jun-18	Apr-18	Apr-18	May-18
2031	88.89	116.46				
2032	90.59	120.22				
2033	92.30	124.19				
2034	94.02	128.00				
2035	95.79	132.13				
2036	97.56	135.49				
2037	99.41	141.64				
2038	101.40	146.12				
2039	103.31	150.07				
2040	105.28	154.52				



Source: Siemens, various sources.

7.2.4 Columbia Coal

Coal sourced from Columbia is forecasted based on Siemens' 2018 spring outlook for Illinois Basin (ILB) coal together with the historical relationship of Columbia coal prices to ILB coal prices. Note that the Exhibits below do not include a flat $10/ton adder for transportation, but this is added to the delivered fuel price for the AES plant that can be found below.

Exhibit 7-10 Columbia Coal Mine Mouth Price Forecast (nominal$/ton)

Unit	nom$/ ton
Date	**Jul-18**
2018	69.43
2019	62.24
2020	58.76
2021	59.02
2022	58.02
2023	58.41
2024	57.69
2025	58.51
2026	59.61
2027	60.73
2028	61.88
2029	63.05
2030	64.24
2031	65.46
2032	66.69
2033	67.95
2034	69.24
2035	70.55
2036	71.89
2037	73.28
2038	74.71
2039	76.17
2040	77.66

7.2.5 Forecast Delivered Fuel Prices at Key Power Plants

The tables below provide Siemens' outlook for delivered fuel prices to the four sides of Puerto Rico (Aguirre, San Juan / Palo Seco, Costa Sur, EcoEléctrica, Mayagüez, and Yabucoa). The forecasts are built from Siemens' base commodity prices for natural gas and crude oil prices, which are then adapted to diesel, residual fuel oil, and LPG based on a historical regression analysis of the relationship between these petroleum products and WTI prices. Finally, cost adders are applied to the base commodity prices to derive delivered fuel prices. The adders were derived from current contractual obligations as provided by PREPA's Fuels Office. Delivered coal and LPG fuel prices are also included below.

The Reference Case or Base Case used in the capacity expansion modeling and supplemental runs corresponds to the first value presented for each fuel, which is followed by the corresponding forecast one standard deviation above and one standard deviation below, that were used for the High and Low case (see further discussion on this selection below).

The forecasted delivered price of natural gas to Costa Sur is explicitly coupled to the price of natural gas at the U.S. benchmark Henry Hub trading point to reflect current fuel supply contract terms at that plant. Siemens applied the following pricing formula to every month of the forecast for LNG delivered to Costa Sur: (50%*P1 + 50%*P2)*HRN_F or specifically [(12.15% * NY HFO No. 6 + 1.125) * 50% + (115% * Henry Hub + 5.95) * 50%] * 0.97. For the remaining plants (San Juan / Palo Seco, Mayagüez, and Yabucoa), Siemens used a

Henry Hub price plus $2.80/MMBtu for liquefaction, $1.00 for transport, and $0.55 for margin, totaling $4.35. Accordingly, the price of natural gas in the form of LNG delivered to power plants in Puerto Rico is linked to the outlook for Henry Hub prices, which in turn is developed using the fundamentals-based GPCM® tool, which is described in more detail in the Attachment A. Siemens' Henry Hub forecast incorporates updated assumptions for natural gas demand, supply, and infrastructure and also benchmarks its short-term natural gas forecast to recent market forwards.

Although standard scale LNG deliveries from the mainland U.S. would be difficult under the restrictions of the Jones Act, the forecasts are based on Henry Hub pricing to align with current fuel supply contract terms. The ultimate fate of the Jones Act remains under debate. However, Henry Hub-based contracts are very liquid and commonly used, reflecting the supply-demand balance (and thus market-clearing prices) in North American natural gas markets. U.S. LNG deliveries to markets such as Mexico are typically indexed to the Henry Hub. While standard scale LNG could be delivered from non-U.S. sources such as Trinidad & Tobago, the pricing would be expected to be competitive with U.S.-sourced LNG. Siemens' estimate of the cost components of LNG from Trinidad & Tobago's Atlanta LNG trains 1-3 range from $2.50 to $4.00/MMBtu for the commodity, from $1.00 to $2.70/MMBtu for liquefaction costs, from $0.50 to $1.00/MMBtu for transportation, and from $1.00 to $2.00/MMBtu for margin, putting the costs for Trinidad & Tobago-sourced LNG in a roughly similar range as U.S.-sourced LNG. More distant sources of LNG, such as Qatar, could potentially supply Puerto Rico but shippers' margins would still reflect to a degree the price of competing sources of LNG like the U.S. or Trinidad & Tobago.

The EcoEléctrica gas prices assumes that on 2022 the contract is renegotiated and all fixed costs including regasification are blended in a renegotiated fixed payment. The gas prices 2022 onwards reflects the cost of the commodity, liquefaction and transportation only and assume that the long-term contract that EcoEléctrica had for reduced natural gas prices expires.

For the high and low delivered LNG price scenarios, Siemens used a plus or minus one standard deviation band around the expected base commodity fuel price for Henry Hub. This high-low band captures the 84.1st percentile band above the expected price and the 15.9th percentile below the expected price, respectively. At the 84.1st percentile price, we can make the following statement, "With 84.1% confidence, the price of natural gas will be at or below X dollars per MMBtu in a given year or alternatively there is only a 15.9% chance that gas prices will exceed X dollars per MMBtu in that same given year." The percentiles cannot be treated as one price path, but rather the probability of being above or below that price in that one given year. The construction of a high- or low-price scenario reflects a sustained price at a given probability level, and the probability of natural gas prices remaining at that level over time is extremely low. For example, if there is a 0.159 chance of higher prices in any one year, there is only a 0.159*0.159 or 2.53% chance of being above the forecast for two years in a row (if prices from one year to the next are independent). Because the price path in the high gas price scenario remains at the plus one standard deviation path for the entire forecast, the path we use has a very low probability (even if prices from year to year are somewhat dependent). Hence a sustained plus or minus one standard deviation band and the expected price trajectory is actually much more conservative than it might appear. Considering a very low-probability price path (i.e., sustained extremely high prices at plus two standard deviations) for natural gas can tell us that a generation decision could change in the extreme case. However, planning decisions should be made on plausible boundaries rather than extreme conditions. In addition, the aforementioned reduction in historical Henry Hub

pricing and price volatility provides the rationale for using a plus or minus one standard deviation band for the base commodity price component of delivered LNG.

Exhibit 7-11. Delivered Aguirre Fuel Price Forecast (Nominal$/MMBtu)

Plant	Aguirre	Aguirre	Aguirre	Aguirre	Aguirre	Aguirre	Aguirre	Aguirre	Aguirre	Aguirre	Aguirre
Fuel	Natural Gas	Gas @ -1SD	Gas @ +1SD	Gas @ 5th	Gas @ 95th	Diesel	Diesel @ -1SD	Diesel @ +2SD	RFO	RFO @ -1SD	RFO @ +2SD
2018	7.70	7.53	7.65	7.51	7.67	16.44	16.18	16.60	11.48	11.26	11.61
2019	7.48	7.14	7.52	7.08	7.58	16.18	15.29	16.81	11.26	10.53	11.79
2020	7.56	7.00	7.77	6.90	7.91	16.62	15.13	18.16	11.64	10.40	12.91
2021	7.99	7.17	8.46	6.99	8.79	16.98	14.58	19.79	11.94	9.96	14.27
2022	8.11	7.01	8.97	6.74	9.49	16.79	13.73	21.45	11.79	9.26	15.65
2023	8.37	6.75	9.81	6.36	10.84	16.88	12.95	24.57	11.87	8.62	18.24
2024	8.67	6.96	10.51	6.53	12.27	17.16	12.48	29.75	12.11	8.23	22.53
2025	8.93	7.17	10.63	6.70	12.37	17.72	12.57	31.58	12.57	8.32	24.05
2026	9.14	7.21	11.07	6.73	13.29	18.35	13.07	32.75	13.11	8.73	25.03
2027	9.23	7.31	11.10	6.81	13.20	18.84	13.37	32.72	13.52	8.99	25.01
2028	9.34	7.40	11.27	6.82	13.47	19.43	13.67	34.00	14.01	9.24	26.07
2029	9.40	7.36	11.37	6.81	13.98	20.33	14.22	35.49	14.76	9.70	27.31
2030	9.59	7.50	11.66	6.76	13.62	21.21	14.65	37.87	15.50	10.07	29.29
2031	9.65	7.25	11.80	6.70	14.15	21.76	14.98	38.74	15.96	10.35	30.01
2032	9.90	7.45	12.13	6.78	14.31	22.17	15.20	40.07	16.31	10.54	31.12
2033	10.07	7.60	12.32	6.88	14.87	22.59	15.54	40.55	16.66	10.82	31.53
2034	10.31	7.64	12.95	6.93	15.67	23.02	15.74	42.21	17.02	11.00	32.91
2035	10.55	7.88	13.25	7.11	15.38	23.45	15.71	42.99	17.39	10.98	33.56
2036	10.73	7.82	13.53	7.07	16.62	23.89	16.48	43.27	17.76	11.63	33.80
2037	10.96	8.14	13.85	7.19	17.10	24.35	16.79	44.11	18.15	11.89	34.51
2038	11.06	8.17	13.76	7.14	16.79	24.83	17.06	45.60	18.55	12.12	35.75
2039	11.15	8.00	13.76	7.04	18.15	25.31	17.24	46.00	18.96	12.28	36.09
2040	11.30	8.09	13.96	7.11	18.44	25.80	17.66	47.57	19.37	12.64	37.39

Source workpaper: PREPA Fuel Forecast 06032019_FINAL_with formulas.xlsx

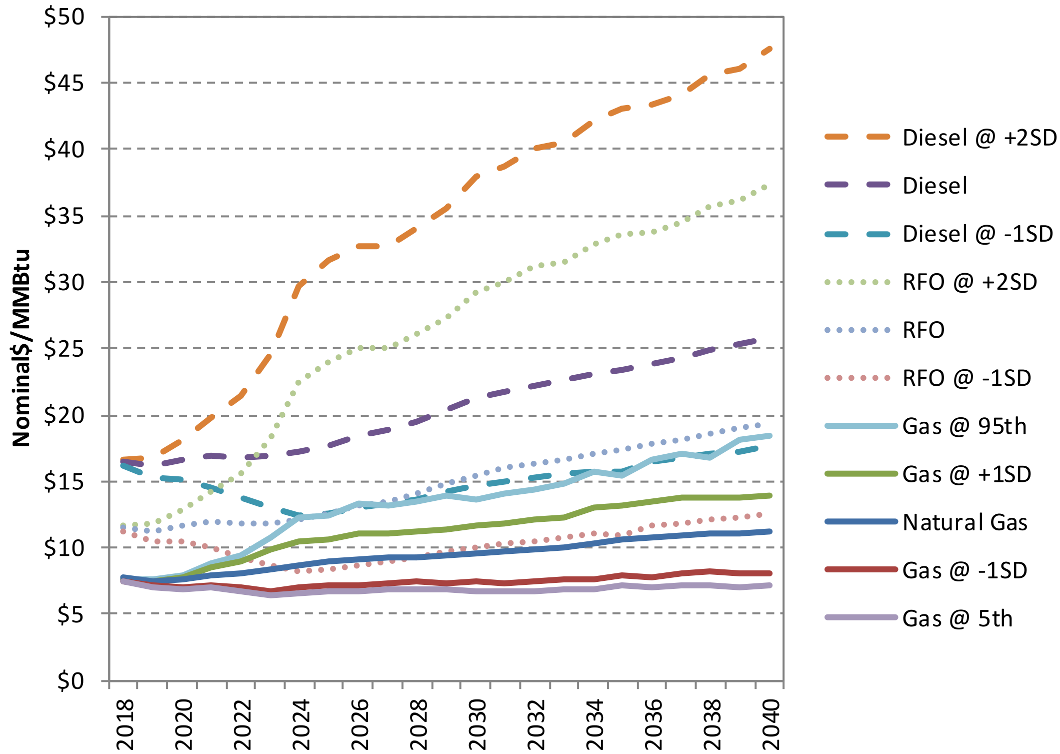


Exhibit 7-12. Delivered Fuels Price Forecast to San Juan / Palo Seco / Mayagüez / Yabucoa (Nominal$/MMBtu)

Plant	SJ-PS-M-Y	SJ-PS-M-Y	SJ-PS-M-Y	SJ-PS-M-Y	SJ-PS-M-Y	SJ-PS-M-Y	SJ-PS-M-Y	SJ-PS-M-Y	SJ-PS-M-Y	SJ-PS-M-Y	SJ-PS-M-Y
Fuel	**Natural Gas**	**Gas @ -1SD**	**Gas @ +1SD**	**Gas @ 5th**	**Gas @ 95th**	**Diesel**	**Diesel @ -1SD**	**Diesel @ +2SD**	**RFO**	**RFO @ -1SD**	**RFO @ +2SD**
2018	7.70	7.53	7.75	7.51	7.77	16.44	16.18	16.60	11.13	10.91	11.26
2019	7.48	7.14	7.62	7.08	7.68	16.18	15.29	16.81	10.91	10.17	11.43
2020	7.56	7.00	7.87	6.90	8.01	16.62	15.13	18.16	11.27	10.04	12.55
2021	7.99	7.17	8.46	6.99	8.79	16.98	14.58	19.79	11.57	9.59	13.90
2022	8.11	7.01	8.97	6.74	9.49	16.79	13.73	21.45	11.41	8.88	15.27
2023	8.37	6.75	9.81	6.36	10.84	16.88	12.95	24.57	11.49	8.23	17.85
2024	8.67	6.96	10.51	6.53	12.27	17.16	12.48	29.75	11.72	7.84	22.14
2025	8.93	7.17	10.63	6.70	12.37	17.72	12.57	31.58	12.18	7.92	23.66
2026	9.14	7.21	11.07	6.73	13.29	18.35	13.07	32.75	12.70	8.33	24.63
2027	9.23	7.31	11.10	6.81	13.20	18.84	13.37	32.72	13.11	8.58	24.60
2028	9.34	7.40	11.27	6.82	13.47	19.43	13.67	34.00	13.59	8.82	25.65
2029	9.40	7.36	11.37	6.81	13.98	20.33	14.22	35.49	14.33	9.28	26.89
2030	9.59	7.50	11.66	6.76	13.62	21.21	14.65	37.87	15.06	9.63	28.86
2031	9.65	7.25	11.80	6.70	14.15	21.76	14.98	38.74	15.52	9.91	29.57
2032	9.90	7.45	12.13	6.78	14.31	22.17	15.20	40.07	15.86	10.09	30.67
2033	10.07	7.60	12.32	6.88	14.87	22.59	15.54	40.55	16.20	10.37	31.07
2034	10.31	7.64	12.95	6.93	15.67	23.02	15.74	42.21	16.55	10.53	32.44
2035	10.55	7.88	13.25	7.11	15.38	23.45	15.71	42.99	16.91	10.50	33.08
2036	10.73	7.82	13.53	7.07	16.62	23.89	16.48	43.27	17.27	11.14	33.32
2037	10.96	8.14	13.85	7.19	17.10	24.35	16.79	44.11	17.66	11.39	34.01
2038	11.06	8.17	13.76	7.14	16.79	24.83	17.06	45.60	18.05	11.62	35.25
2039	11.15	8.00	13.76	7.04	18.15	25.31	17.24	46.00	18.44	11.76	35.57
2040	11.30	8.09	13.96	7.11	18.44	25.80	17.66	47.57	18.85	12.11	36.87

Source workpaper: PREPA Fuel Forecast 06032019_FINAL_with formulas.xlsx

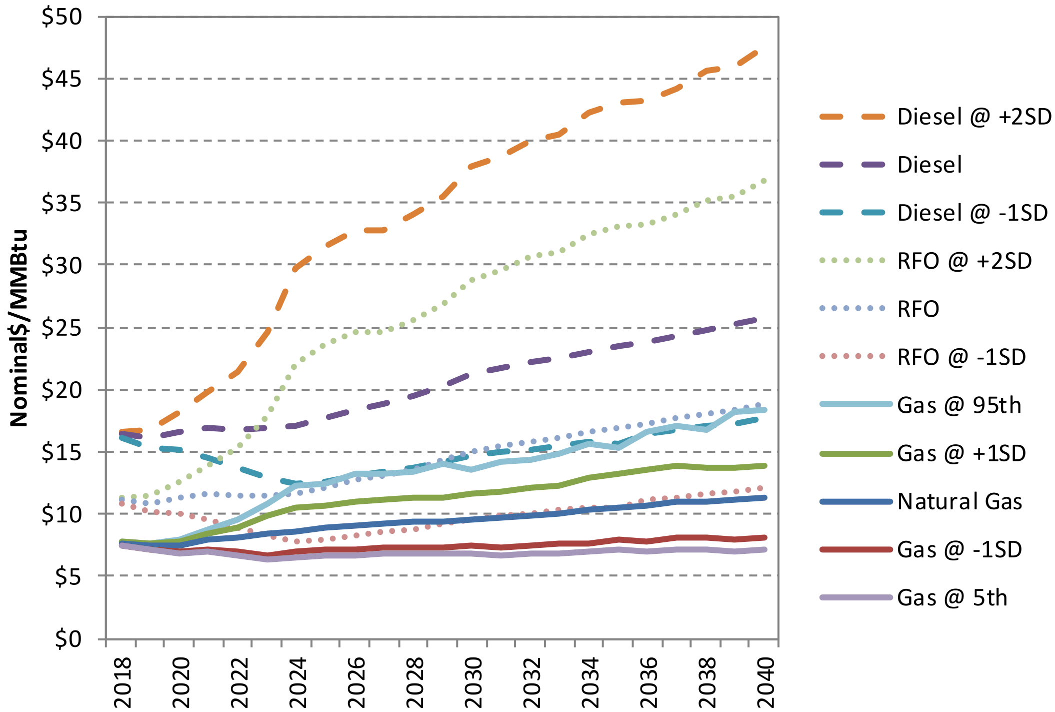
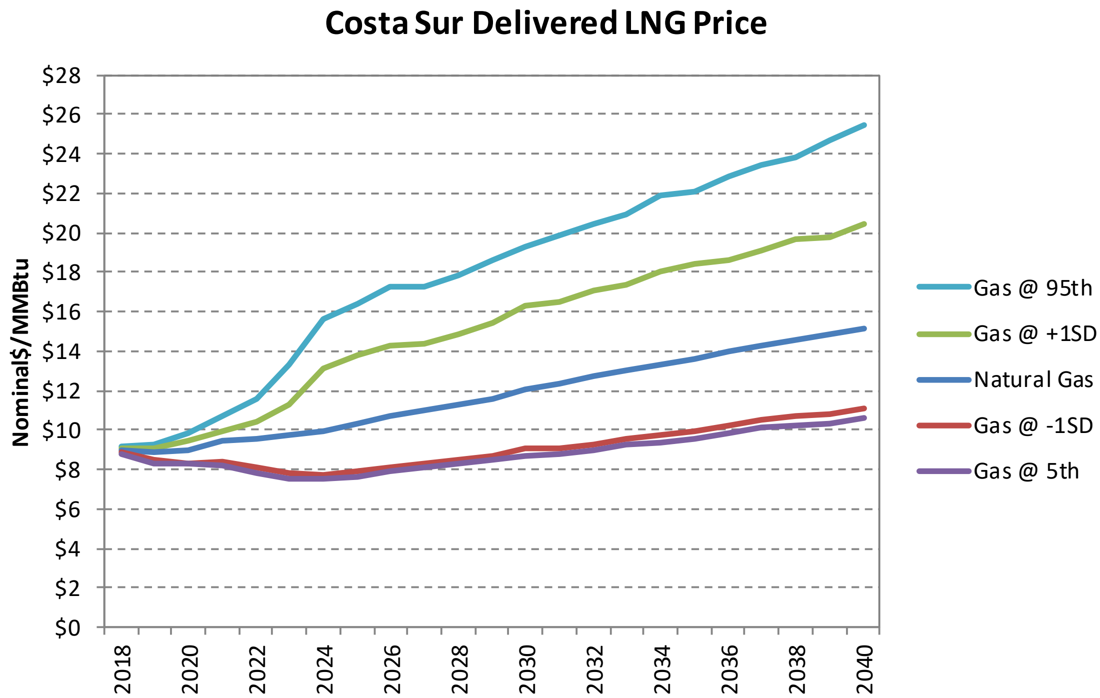
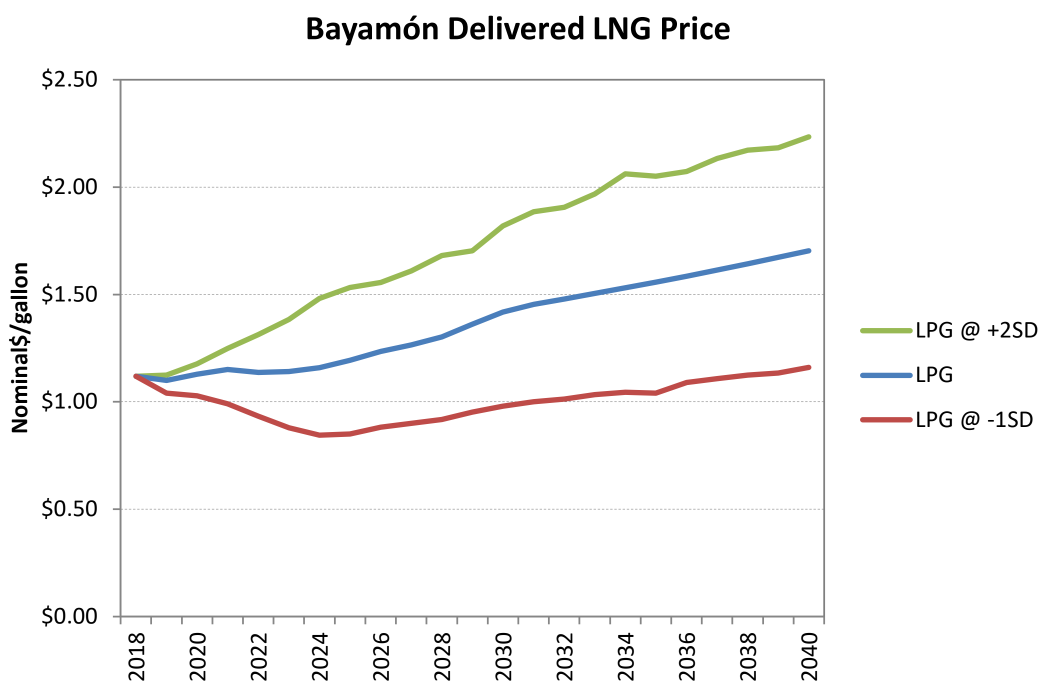


Exhibit 7-13. Delivered Natural Gas to Costa Sur, LPG to Bayamón, and Coal to AES

Plant	Costa Sur	Costa Sur	Costa Sur	Costa Sur	Costa Sur	Baya-món	Baya-món	Baya-món	AES	AES	AES
Fuel	**Natural Gas**	**Gas @ -1SD**	**Gas @ +1SD**	**Gas @ 5th**	**Gas @ 95th**	**LPG**	**LPG @ -1SD**	**LPG @ +2SD**	**Coal**	**Coal @ -1SD**	**Coal @ +1SD**
Year/ Unit	**nom$/ MMBtu**	**nom$/ MMBtu**	**nom$/ MMBtu**	**nom$/ MMBtu**	**nom$/ MMBtu**	**nom$/ gallon**	**nom$/ gallon**	**nom$/ gallon**	**nom$/ tonne**	**nom$/ tonne**	**nom$/ tonne**
2018	9.02	8.88	9.12	8.78	9.18	1.12	1.12	1.12	79.43	79.43	79.43
2019	8.89	8.51	9.05	8.35	9.26	1.10	1.04	1.14	72.24	68.55	76.23
2020	8.98	8.32	9.45	8.26	9.89	1.13	1.03	1.23	68.76	59.63	79.62
2021	9.42	8.39	9.91	8.19	10.69	1.15	0.99	1.34	69.02	57.21	83.77
2022	9.51	8.08	10.40	7.86	11.61	1.14	0.93	1.45	68.02	56.42	82.53
2023	9.71	7.79	11.31	7.49	13.30	1.14	0.88	1.66	68.41	56.73	83.02
2024	9.97	7.73	13.09	7.49	15.67	1.16	0.85	2.00	67.69	56.15	82.11
2025	10.31	7.89	13.83	7.67	16.36	1.19	0.85	2.12	68.51	56.81	83.14
2026	10.69	8.10	14.28	7.90	17.23	1.23	0.88	2.20	69.61	57.69	84.51
2027	10.97	8.34	14.39	8.11	17.24	1.27	0.90	2.19	70.73	58.59	85.92
2028	11.26	8.53	14.90	8.27	17.84	1.30	0.92	2.28	71.88	59.51	87.35
2029	11.61	8.74	15.42	8.51	18.63	1.36	0.95	2.37	73.05	60.44	88.81
2030	12.07	9.05	16.30	8.69	19.27	1.42	0.98	2.53	74.24	61.39	90.30
2031	12.38	9.12	16.52	8.84	19.87	1.45	1.00	2.59	75.46	62.37	91.82
2032	12.70	9.32	17.11	9.02	20.44	1.48	1.01	2.67	76.69	63.35	93.37
2033	12.99	9.59	17.41	9.25	20.93	1.50	1.03	2.71	77.95	64.36	94.94
2034	13.31	9.78	18.02	9.41	21.92	1.53	1.04	2.81	79.24	65.39	96.55
2035	13.65	9.92	18.46	9.57	22.10	1.56	1.04	2.86	80.55	66.44	98.18
2036	13.95	10.21	18.60	9.87	22.87	1.59	1.09	2.88	81.89	67.51	99.86
2037	14.29	10.55	19.10	10.11	23.45	1.61	1.11	2.93	83.28	68.63	101.61
2038	14.58	10.75	19.67	10.26	23.85	1.64	1.12	3.03	84.71	69.77	103.39
2039	14.86	10.85	19.80	10.35	24.72	1.67	1.13	3.06	86.17	70.94	105.21
2040	15.19	11.06	20.42	10.61	25.44	1.70	1.16	3.16	87.66	72.12	107.07

Source workpaper: PREPA Fuel Forecast 06032019_FINAL_with formulas.xlsx


Costa Sur Delivered LNG Price
Nominal$/MMBtu
$28
$26
$24
$22
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Gas @ 95th
Gas @ +1SD
Natural Gas
Gas @ -1SD
Gas @ 5th


Bayamón Delivered LNG Price
Nominal$/gallon
$2.50
$2.00
$1.50
$1.00
$0.50
$0.00
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
LPG @ +2SD
LPG
LPG @ -1SD

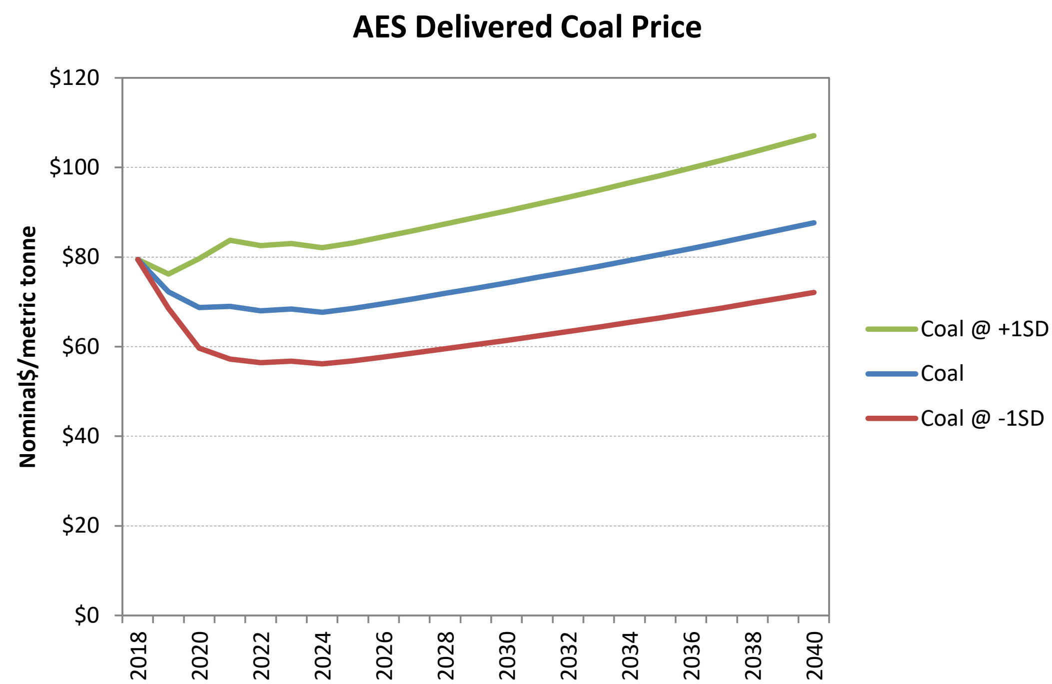
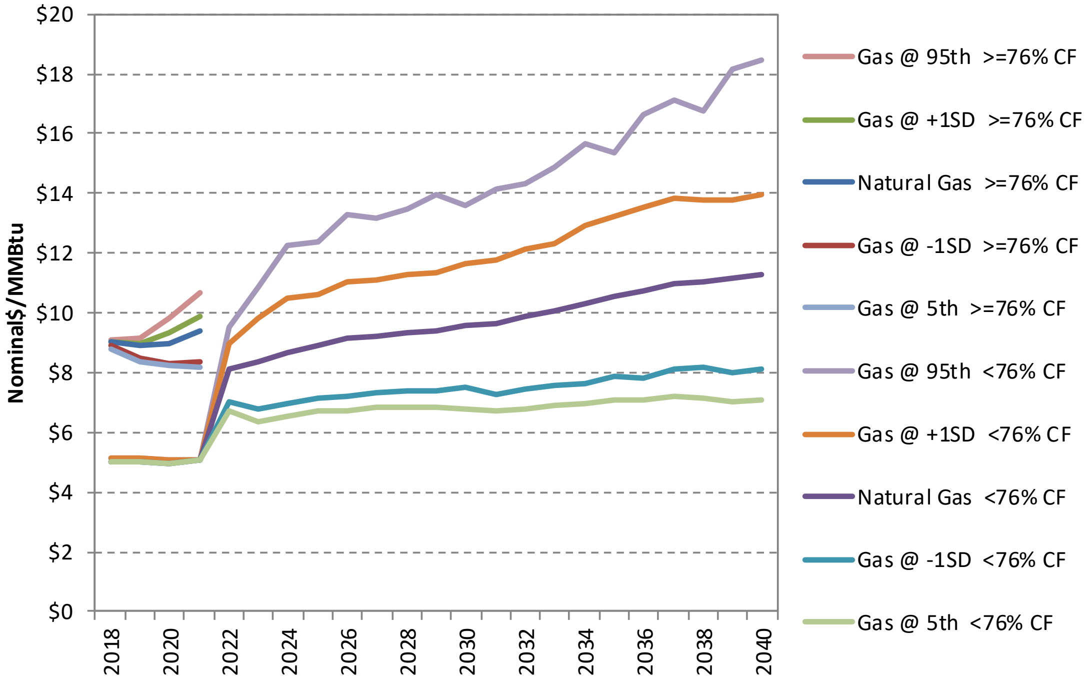


Exhibit 7-14. Delivered EcoEléctrica Natural Gas Price Forecast (Nominal$/MMBtu)

Plant	Eco-Eléc-trica	Eco-Eléc-trica	Eco-Eléc-trica	Eco-Eléc-trica	Eco-Eléc-trica	Eco-Eléc-trica	Eco-Eléc-trica	Eco-Eléc-trica	Eco-Eléc-trica	Eco-Eléc-trica
Fuel	Natural Gas	Gas @ -1SD	Gas @ +1SD	Gas @ 5th	Gas @ 95th	Natural Gas	Gas @ -1SD	Gas @ +1SD	Gas @ 5th	Gas @ 95th
Capa-city Factor	>=76% CF	>=76% CF	>=76% CF	>=76% CF	>=76% CF	<76% CF	<76% CF	<76% CF	<76% CF	<76% CF
2018	9.02	8.88	9.02	8.78	9.08	5.04	5.04	5.14	5.04	5.14
2019	8.89	8.51	8.95	8.35	9.16	5.04	5.04	5.14	5.04	5.14
2020	8.98	8.32	9.36	8.26	9.80	4.96	4.96	5.06	4.96	5.06
2021	9.42	8.39	9.91	8.19	10.69	5.06	5.06	5.06	5.06	5.06
2022						8.11	7.01	8.97	6.74	9.49
2023						8.37	6.75	9.81	6.36	10.84
2024						8.67	6.96	10.51	6.53	12.27
2025						8.93	7.17	10.63	6.70	12.37
2026						9.14	7.21	11.07	6.73	13.29
2027						9.23	7.31	11.10	6.81	13.20
2028						9.34	7.40	11.27	6.82	13.47
2029						9.40	7.36	11.37	6.81	13.98
2030						9.59	7.50	11.66	6.76	13.62
2031						9.65	7.25	11.80	6.70	14.15
2032						9.90	7.45	12.13	6.78	14.31
2033						10.07	7.60	12.32	6.88	14.87
2034						10.31	7.64	12.95	6.93	15.67
2035						10.55	7.88	13.25	7.11	15.38
2036						10.73	7.82	13.53	7.07	16.62
2037						10.96	8.14	13.85	7.19	17.10
2038						11.06	8.17	13.76	7.14	16.79
2039						11.15	8.00	13.76	7.04	18.15
2040						11.30	8.09	13.96	7.11	18.44

Source workpaper: PREPA Fuel Forecast 06032019_FINAL_with formulas.xlsx



7.3 Value of Lost Load Estimation

As part of PREPA's Integrated Resource Planning (IRP), Siemens performed a loss of load analysis to assess the likelihood that due to generation and/or transmission outages, the system will be unable to meet load for any period of time. The objective of the analysis is to identify hours in which local or system wide supply may be inadequate to meet demand.

The analysis is performed using a Monte-Carlo simulation to capture loss of load hours (LOLH) and Energy Not Served (ENS) considering the expected performance of the generating fleet and the impact of normal transmission limitations. Additionally, for the impact of weather events two approaches are being considered:

Model a Scenario representative of system condition after a major storm that is expected to occur with relative frequency (e.g. Category 1 Hurricane) and evaluate the LOLH and ENS for a period of 1 month assuming that the system will stay in this condition.

Model a Scenario of the system condition after a major storm that is expected to occur more infrequently (e.g. a Cat 4 Hurricane) in which the system is split into the pre-designed regions (called MiniGrids). Each MiniGrid is assumed to operate in isolation for 1 month. An estimation of load not served during MiniGrid formation can be included.

As part of this IRP, Siemens has estimated the value of lost load (VOLL) based on methodologies applied in other countries or regions. To meet the IRP objectives, Siemens computed a VOLL adjustment for each of the portfolios to evaluate the expected total cost including the cost of maintaining resiliency, which FERC defined as: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability

to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[59] The VOLL in turn impacts the selection of the recommended portfolio(s) for PREPA. Specifically, one of the IRP objectives is least cost. Traditional IRPs measure the Net Present Value (NPV) of revenue requirements over the IRP planning horizon. Adding VOLL to the NPV of revenue requirements captures the value of a resilient system in the least cost measure.

VOLL is the standard metric used to estimate the economic impact of disruptions in power service to customers, and thus can provide a measure of the magnitude of benefits associated with decreasing the likelihood of power system interruptions. In principle, VOLL is the value that represents a customer's willingness to pay for reliable electricity service or to avoid an outage. 60

VOLL is determined by relating the monetary damage arising from a power interruption (due to the loss of economic activities) to the level of the MWh that is not supplied during an interruption. VOLL is generally measured in US$/MWh. The value of energy not served (ENS) is determined as the VOLL x ENS. VOLL is typically valued separately for different user groups, e.g. residential, commercial and industrial users. The reason for this is that different users are affected differently by the same power interruption.[61]

7.3.1 Methodological Approaches to Estimating VOLL

There are four key methodologies used for estimating VOLL in the field of economics. Exhibit 7-15 shows a brief explanation of each methodology, followed by its theoretical and practical strengths and weaknesses.

Exhibit 7-15. Key Methodologies Used for Estimating VOLL

Method	Description	Strength	Weakness
Revealed Preference Survey (Market Behavior)	▪ Use of surveys to determine expenditures customers incur to ensure reliable generation (i.e., back-up generators and interruptible contracts) to estimate VOLL	▪ Uses actual customer data that is generally reliable.	▪ Only relevant if customers invest in back-up generation ▪ Limited consideration of duration and/or timing of outages ▪ Difficult for residential customers to quantify expenses
Stated Choice Survey (WTA/WTP)	▪ Use of surveys /interviews to infer a customer's willingness-to-pay (WTP), willingness-to-accept (WTA) and trade-off preferences	▪ More directly incorporates customer preferences ▪ Includes some indirect costs and considers duration and/or timing of outages	▪ Time-consuming ▪ Need to manage for potential biases ▪ Large discrepancy between WTP and WTA ▪ Residential customers may give unreliable answers due to lack

[59] FERC Docket No. AD18-7-000

[60] London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewand Macroeconomic.pdf

[61] Institute of Energy and Climate Research – Systems Analysis and Technology Evaluation (IEK-STE), (2015, December). Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review. Retrieved from https://www.frontiersin.org/articles/10.3389/fenrg.2015.00055/full.

			of experience
Macroeconomic Analysis	▪ Uses macroeconomic data and other observable expenditures to estimate VOLL. ▪ This approach estimates VOLL by estimating the value of loss of production for non-residential customers and/or the value loss of leisure time for residential customers.	▪ Few variables ▪ Easy to obtain data ▪ GNP reasonable proxy for business VOLL	▪ Does not consider linkages between sectors, productive activities ▪ Proxies for cost of residential outages may be arbitrary or bias
Case Study Analysis (Blackout Studies)	▪ Examines actual outages to determine VOLL. In this approach, the resulting damage costs of a real power interruption are recorded retrospectively.	▪ Uses actual, generally reliable data	▪ Costly to gather data ▪ Available case studies may not be representative of other outages/jurisdictions

Note:
WTP: how much they would pay to either avoid a blackout or to be guaranteed a higher level of supply security.
WTA: how much money consumers would have to be offered for them to accept a reduction in supply security or to retain the present level of security instead of being upgraded to a higher level.
Sources:

1. London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf,
2. Institute of Energy and Climate Research – Systems Analysis and Technology Evaluation (IEK-STE), (2015, December).
3. Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review. Retrieved from https://www.frontiersin.org/articles/10.3389/fenrg.2015.00055/full.

7.3.2 VOLL Trends

VOLL estimates are extremely sensitive to a number of factors, including assumptions used in survey analysis, time and duration of outage, time of advanced notification of outage, customer profile, industry sector and many other factors. Average VOLLs for a developed, industrial economy range from approximately $9,000/MWh to $45,000/MWh. Looking on a more disaggregated level, residential customers generally have a lower VOLL ($0/MWh - $17,976/MWh) than commercial and industrial (C&I) customers (whose VOLLs range from about $3,000/MWh to $53,907/MWh).[62] Other trends include:

In general, residential customers are expected to have the lowest VOLLs, while small C/I customers have the highest VOLLs. Small C/I customers are more labor and capital intensive than residential customers and are less likely to prepare for operational risks such as outages by using interruptible contracts and back-up generation as hedges against outages than medium and large C/I customers, leading to generally higher VOLLs.

[62] London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewand Macroeconomic.pdf

Residential VOLLs in the U.S. are in the $1,000/MWh – $4,000/MWh range, while VOLLs in international jurisdictions tend to be much higher. This variation may be due to a variety of factors, including different consumption patterns and costs of electricity in the regions studied, as well as the different methodologies used to estimate VOLL in each study.

Long duration outages lead to higher VOLL as the indirect and induced costs of the outage increase over time (loss of wages, loss of perishable goods, etc.).

Exhibit 7-16 shows the results of recent VOLL studies, broken down according to methodology applied and end-user group. Due to the different degrees of differentiation, the VOLL results of the studies are shown as ranges. [63]

Exhibit 7-16. Results of Recent VOLL Studies

Region/Market	Methodology	System-wide VOLL	Residential	Non-Residential	
				Large C/I	*Small C/I*
US - Southwest	Analysis of past survey results		$0	$8,774	$35,417
US - MISO	Analysis of past survey results/ Macroeconomic analysis		$1,735	$29,299	$42,256
				Commercial	*Industrial*
Austria	Survey		$1,544		
New Zealand	Survey	$41,269	$11,341	$77,687	$30,874
Australia - Victoria	Survey	$44,438	$4,142	$28,622	$10,457
Australia	Analysis of past survey results	$45,708			
Republic of Ireland (2010)	Macroeconomic analysis	$9,538	$17,976	$10,272	$3,302
Republic of Ireland (2007)	Macroeconomic analysis	$16,265			
US - Northeast	Macroeconomic analysis	$9,283-$13,925			

Note: All values in 2012 US$/MWh

Sources: London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

7.4 First Approach to Calculate Puerto Rico's VOLL

One approach to calculate Puerto Rico's VOLL is to understand which of the nine jurisdictional studies shown in Exhibit 7-16 has the most similarities to Puerto Rico. The applicability of the VOLL estimates from the nine jurisdictional studies to Puerto Rico is determined by considering the similarities between the studied geographic region/market and Puerto Rico. The metrics include: (1) economic and demographic (population and GNP, urban/rural, temperature); (2) electricity consumption patterns; and (3) market design. The mix of customer class also plays a role. In FY2016, residential, small C&I[64], and medium/large C&I[65] customers represented approximately 38%, 13% and 50% respectively

[63] London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

[64] Small C&I= customers with an annual consumption under 50,000 kWh

[65] Medium/Large C&I = customers with an annual consumption over 50,000 kWh

of PREPA's total sales. As shown in Exhibit 7-17, the most applicable study to PREPA is New Zealand, which has a system-wide VOLL of $41,269/MWh (Residential: $11,341/MWh, Commercial: $77,687/MWh, Industrial: $30,874/MWh) in 2012 dollar.

Exhibit 7-17. Proxy Estimates with Potential Applicability to PREPA

Economic and Demographic Factors	Puerto Rico	New Zealand[5]	Ireland[5]	Victoria, Australia[5]	Australia[5]
Population Density (people/mile²)[1]	385	42	168	64	7.3
Average Temperatures (°F)[3]	Winter: 64 Summer: 71	Winter:50-59 Summer:68-86	Winter:42 Summer:58	Winter:44-59 Summer:57-79	Winter:33-91 Summer:51-97
GNP per Capita (2011 USD$)[2]	35,093	38,563	48,423	59,378	60,979
Rural (%)[3]	1% rural	14% rural	38% rural	6.5% rural	11% rural
Electricity Consumption Patterns					
Total Annual Consumption (MWh)[4]	16,995,838	40,700,000	26,100,000	56,250,000	225,000,000
Peak Demand (MW)[4]	3,685	6,330	5,090	9,378	13,781
Market Design					
Wholesale Market[6]	No	Yes	Yes	Yes	Yes
Retail Market[6]	No	Yes	Yes, but limited	Yes	Yes
Connection with other systems[6]	No	No	Yes, limited	Yes	No
Overall Applicability[6]		High	High	Moderate	Moderate

Sources:

1. Trading Economics. Retrieved from https://tradingeconomics.com/puerto-rico/population-density-people-per-sq-km-wb-data.html
2. World Bank (2015, April). https://data.worldbank.org/indicator/NY.GDP.PCAP.PP.CD?order=wbapi_data_value_2013+wbapi_data_value+wbapi_data_value-last&sort=desc
3. NREL. (2015, March). Energy Transition Initiative. Retrieved from https://www.nrel.gov/docs/fy15osti/62708.pdf
4. PREPA (FY2016-2017)
5. London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

Adapting New Zealand's VOLL estimates of each sector and using the expected unserved power (kWh) per sector specific for Puerto Rico (using Puerto Rico's reliability index[66] and consumer load consumption), Puerto Rico's system wide VOLL results in $31,897/MWh in 2018 dollar as shown in Exhibit 7-18.

[66] See Exhibit 7-18 and Exhibit 7-19 for more detail on reliability index.

Exhibit 7-18. 1st Approach VOLL Results Applicable to PREPA

Sector	Number of Customers	Unserved Energy	Cost Per Average MWh	Total Cost
		MWh	2018$MWh	2018$
Residential	1,335,643	10,345	12,269	126,926,034
Small C&I	116,094	3,490	84,045	293,332,602
Medium and Large C&I	11,707	13,650	33,401	455,926,165
Total	1,463,444	27,471	31,895	876,184,801

Sources: Siemens, PREPA

7.5 Second Approach to Calculate Puerto Rico's VOLL

Puerto Rico's power grid is unique as it supports a large commercial and industrial load in a tropical climate and a hurricane zone, with pharmaceuticals, textiles, petrochemicals, and electronics being the major industries.

The Interruption Cost Estimate (ICE) calculator is a publicly available web-based tool developed by Lawrence Berkeley National Laboratory (Berkeley Laboratory) designed to estimate economic costs of power interruptions where you can modify the specific parameters/inputs. It is based on more than 20 years of utility-sponsored surveys on the costs of power interruptions to customers. To ensure its continued effectiveness, the tool continues to be augmented by research on the latest methods for collecting and developing information on the economic consequences of power interruptions on businesses, residences, and society at large. [67]

As the first step, Siemens analyzed the reliability indices including System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI) provided by PREPA and shown in Exhibit 7-19. These indices include the effect of all outages including generation transmission and distribution but not the effect of major event days (MED).

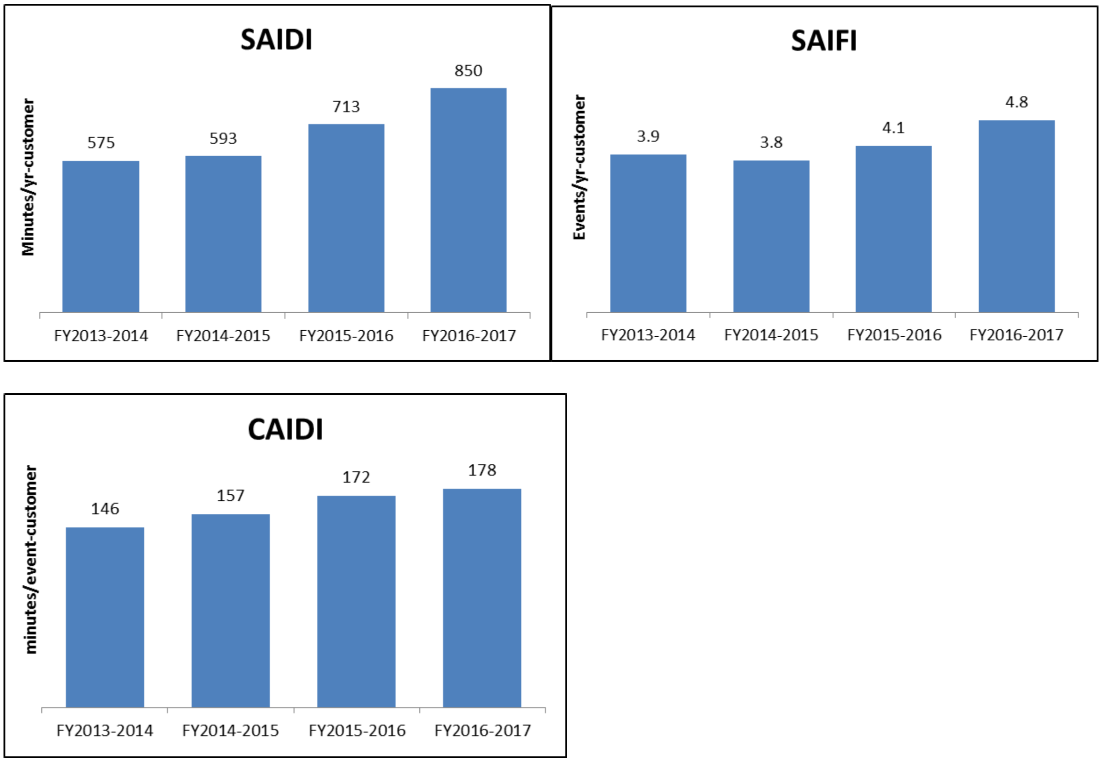
SAIDI index is based on the amount of time the average customers experience a sustained outage in a given year. From FY2013 to FY2016, the average SAIDI for Puerto Rico was about 683 minutes per customer per year.

SAIFI index represents the number of times the average customer experiences a sustained outage in a given year. From FY2013 to FY2016, the average SAIFI for Puerto Rico was about 4.2 events per customer per year.

CAIDI index represents the average restoration time when customers are impacted by a sustained outage. It is determined by dividing SAIDI by SAIFI. From FY2013 to FY2016, the average CAIDI for Puerto Rico was 163 minutes per event per customer.

[67] Berkeley Lab's Electricity Markets & Policy Group (EMP Group). (2018). Interruption Cost Estimation (ICE) Calculator. Retrieved from https://icecalculator.com/interruption-cost

Exhibit 7-19. Puerto Rico's Reliability Indexes (SADI, SAIFI, and CAIDI)



Source: PREPA (IEEE Benchmark Report)

As the second step, Siemens introduced other inputs specific for Puerto Rico as presented in Exhibit 7-20.

Exhibit 7-20. PREPA's Parameters to Calculate the Interruption Costs

Parameter	Description	Units	Value
Reliability Index[1]	SAIDI	minute/year-customer	850
	SAIFI	events/year-customer	4.8
	CAIDI	minutes/event-customer	178
Annual Usage per Customer[2]	Residential	MWh/customer	5
	Small C&I	MWh/customer	19
	Medium and Large C&I	MWh/customer	721
Number of Customers per Class[2]	Residential	Number	1,335,643
	Small C&I	Number	116,094
	Medium and Large C&I	Number	11,707
Industry Composition[3]	Construction	%	5%
	Manufacturing	%	9%
	Other Industries	%	86%

Parameter	Description	Units	Value
Household Income[3]	Average	USD	27,017
Power Interruption Distribution[4]	Outages from 5am to 5pm	%	46%
	Outages during Summer (June-Sept)	%	50%
Back-up Generation Percentage per Class[4]	Small C&I with Back-up or Power Conditioning	%	30%
	Medium/ Large C&I with Back-up or Power Conditioning	%	46%
U.S. State[5]	U.S. State	U.S. State	Hawaii

Sources:

1. PREPA- IEEE Benchmark Report (FY2016-2017)
2. PREPA (FY2016-2017)
3. U.S. Bureau of Labor Statistics. Retrieved from https://www.bls.gov/eag/eag.pr.htm,
4. Berkeley Lab's Electricity Markets & Policy Group (EMP Group). (2018). Interruption Cost Estimation (ICE) Calculator. Retrieved from https://icecalculator.com/interruption-cost
5. The ICE Calculator uses a default set of inputs based on the selected state. Puerto Rico is not an option for the ICE Calculator; therefore, Siemens used Hawaii, as it is an island and has a similar GNP as Puerto Rico.

As a result, Siemens estimated Puerto Rico's system-wide VOLL at $57,940/MWh (Residential: $4,037/MWh, Small C&I: $219,237/MWh, Large C&I: $57,488/MWh) in 2018 dollars. The Berkeley Lab's ICE calculator generated results as shown in Exhibit 7-21.

Exhibit 7-21. Second Approach VOLL Results Applicable to PREPA

Sector	Number of Customers	Unserved Energy	Cost Per Average MWh	Total Cost
		kWh	2018$	2018$
Residential	1,335,643	10,345,165	4,037	41,763,433
Small C&I	116,094	3,490,198	219,237	765,180,534
Medium and Large C&I	11,707	13,650,221	57,488	784,723,925
Total	1,463,444	27,471,029	57,940	1,591,667,892

Source: Siemens, Berkeley Lab's Electricity Markets & Policy Group (EMP Group). (2018). Interruption Cost Estimation (ICE)Calculator. Retrieved from https://icecalculator.com/interruption-cost

7.5.1 Conclusion

In summary, the two approaches yielded a wide range of estimated VOLL for Puerto Rico. The second approach estimates Puerto Rico's system-wide VOLL at $57,940 which is $26,043 higher than the first approach. Exhibit 7-22 summarizes the results for the two approaches. The 2nd approach results in small C&I and Medium/Large C&I VOLL numbers that are out of range compared to the literature VOLL trends discussed above as well as in other documentation reviewed. Additionally, Siemens estimated the VOLL for Puerto Rico using other weakly related markets like the Mid Continent ISO (MISO) in the U.S. and obtained values similar to those of method 1 (27,450 in 2018$/MWh). Therefore, for the 2018 IRP, Siemens chose to utilize the results from the first approach as proxy to calculate the value of lost load for PREPA customers.

Exhibit 7-22. PREPA VOLL Estimates

Sector	1st Approach (2018$/MWh)	2nd Approach (2018$/MWh)
Residential	12,270	4,037
Small C&I	84,051	219,237
Medium and Large C&I	33,403	57,488
System	31,897	57,940

Part
8

Resource Plan Development

This section presents the Scenarios, Strategies and Sensitivities described in Part 5, the result of the assessment of the resulting generation plans, and metrics and conclusions associated with the plans.

8.1 Overview of Scenario Results

Siemens investigated initially over 78 LTCE plans as potential resource plans for PREPA. These plans included numerous plausible generation portfolio options including those suggested by stakeholders. These different plans considered points that were critical for the final IRP including, among other issues:

- Uncertainty associated with the future customer demand
- Future prices of generation technologies, e.g., wind, solar, battery storage
- Future prices of fuels, particularly natural gas and the potential availability of infrastructure to deliver additional gas to the island
- Prudent methods to increase resilience and reliability
- Practical limits to PREPA's ability to interconnect new battery energy storage and renewables generation
- Timing of new generation resource additions and the timing of retirements of existing aged fossil fueled resources.
- Contingency planning for deviations in load growth projections

This initial screening of the over 78 LTCE plans resulted in the identification of a set of 34 LTCE plans[68] that were assessed to create the first draft of this IRP. Subsequently and in respond to requests of the PREB and the mandates of Act 17-2019, 35 Cases were assessed to identify the recommended resource plan and the common no regret / minimum regret elements across the plans with perceived merit.

Note that Scenario 2 is not included in the final 35 Cases as S4S2 and S4S3 resulted in the same resources that would be built under the constraints of Scenario 2.

Exhibit 8-1 below provides the main results of the 35 Cases with their Scenario, Strategy. The net present value (NPV) is the present value of the generation revenue requirements

including the return on capital, fuel cost, fixed and variable O&M and regasification (LNG) costs. This NPV should be determined using a discount rate applicable to PREPA as a public utility and for this we selected we 9% (6.86% on a real dollar basis) as this was the same discount rate used in the first IRP and it is based on the assumption that PREPA (or its successors) is able to resolve its current financial issues and can finance its capital expenditures at this rate.

The discount rate used in the NPV calculations above should not be confused with the weighted average cost of capital (WACC) for private parties which is used to determine the fixed costs PREPA would be charged for projects financed by private parties (i.e. the return on capital added to each new generation resource, BESS and LNG terminal).

Other parameters presented include the average cost of generation (all in) for the period 2019 to 2028 in $/MWh, the level of RPS compliance achieved by 2038, the present value of the value of the energy that would be lost in case that the system had to revert to MiniGrid isolated operations for 1 month every 5 years (see further details in this section), the lowest reserve margin observed , a ratio of photovoltaic generation added to the system to the peak load as an indication of technology risk (i.e. potential challenges to manage generation whose output can be much higher than the peak load), reduction in emissions and capital costs.

To help visualize the results in Exhibit 8-1 we provide below a comparison on how the NPV of the different scenarios/portfolios compare and changes with respect of key variables; demand, gas price and renewable costs. To complement this assessment, it is follow by a qualitative analysis using a color scorecard for the different plans /scenarios under similar external conditions (load growth and cost of renewable) and we include other elements as is the case of the technology risk.

Exhibit 8-1: Summary of Investment Decisions by Scenario, Strategy and Load Growth[69]

	Large & Medium CCGTs and Peakers							Renewable and Storage				
Case ID	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peaker Conversion	Other	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)	Customer Owned Gen.2038 (MW)
S1S2B	–	EcoEléctrica Instead	✔	–	–	–	504	2,580	1,280	2,700	1,720	1,176
S1S2H	–	EcoEléctrica Instead	✔	–	–	Costa Sur 5 to 2034	325	2,820	1,360	3,180	1,840	1,176
S1S2L	–	EcoEléctrica Instead	✔	–	–	–	325	2,340	1,240	2,340	1,800	1,176
S1S3B	–	EcoEléctrica Instead	✔	–	–	–	513	2,580	1,280	2,580	1,840	1,176
S1S2S1B	–	EcoEléctrica Instead	✔	–	–	–	504	2,580	1,280	2,700	1,720	1,176
S1S2S5B	–	EcoEléctrica Instead	✔	–	–	–	504	2,580	1,280	2,700	1,720	1,176
S1S2S6B	–	EcoEléctrica Instead	✔	–	–	–	504	2,580	1,280	2,700	1,720	1,176
S1S2S7B	–	EcoEléctrica Instead	–	–	–	Costa Sur 5 to 2036	507	2,880	1,280	3,240	1,760	1,176
S1S1B	–	EcoEléctrica Instead	✔	–	–	Costa Sur 5&6 to 2037 & 2031	301.6	2,520	1,240	2,520	2,080	1,176
S3S2B	–	✔	✔	–	–	–	348	2,820	1,320	4,140	3,000	1,176
S3S2H	–	✔	✔	–	–	–	364	3,300	1,680	4,560	2,600	1,176
S3S2L	–	–	✔	–	–	–	389	3,000	1,600	4,080	2,520	1,176
S3S3B	–	✔	✔	–	–	–	371	2,820	1,280	4,140	2,280	1,176
S3S2S5B	–	✔	✔	–	–	–	348	2,820	1,280	4,140	2,280	1,176
S3S2S8B	–	✔	✔	–	–	–	348	2,820	1,280	4,140	2,280	1,176
S4S2B	✔	✔	✔	–	–	–	371	2,220	1,320	2,820	1,640	1,176
S4S2H	✔	✔	✔	–	–	–	394	2,460	940	2,520	980	1,176

[69] See Part 5 – Resource Needs Assessment for a detailed description of the various Scenarios.

Case ID	Large & Medium CCGTs and Peakers							Renewable and Storage				
	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peaker Conversion	Other	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)	Customer Owned Gen.2038 (MW)
S4S2L	–	✔	✔	–	–	–	434	2,100	960	2,520	1,020	1,176
S4S2S9B	✔	EcoEléctrica Instead	✔	–	–	–	348	2,220	1,320	2,820	1,640	1,176
S4S3B	2027	✔	✔	–	–	–	394	2,580	1,320	2,820	1,320	1,176
S4S2S1B	✔	✔	✔	–	–	–	371	2,220	1,320	2,820	1,640	1,176
S4S2S4B	–	✔	✔	–	–	–	371	2,580	1,320	3,060	1,640	1,176
S4S2S5B	✔	✔	✔	–	–	–	371	2,220	1,320	2,820	1,640	1,176
S4S2S6B	✔	✔	✔	–	–	–	371	2,220	1,320	2,820	1,640	1,176
S4S1B	–	–	✔	2028	–	F-Class at Mayaguez 2025	348	2,700	1,240	2,700	1,640	1,176
S5S1B	–	369 MW (2025&2028)	✔	–	–	–	371	2,580	1,200	2,580	1,480	1,176
S5S1S5B	–	369 MW (2025&2028)	✔	–	–	–	371	2,580	1,200	2,580	1,480	1,176
S5S1S1B	–	369 MW (2025&2028)	✔	–	–	–	371	2,580	1,200	2,580	1,480	1,176
S5S1S6B	–	369 MW (2025&2028)	✔	–	–	–	371	2,580	1,200	2,580	1,480	1,176
ESM	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2,580	1,640	1,176
ESM High	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,340	1,040	2,460	1,040	1,176
ESM Low	✔	EcoEléctrica Instead	✔	✔	✔	–	421	1,920	1,040	1,980	1,040	1,176
ESMS1B	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2,580	1,640	1,176
ESMS6B	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2,580	1,640	1,176
ESMS5B	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2,580	1,640	1,176

(green)	Strong no regret with no variation among cases that support decision being made
(light green)	Decision common to multiple cases / little variation between scenarios that allow the decision to be taken
(yellow)	Decision common to few scenarios that allow the decision to be taken
(orange)	Decision common to one scenario, PV / BESS: outlier or close follow up required.

Source Workpaper: Summary PREPA IRP Cases-06032019_v9.xlsx

Exhibit 8-2: Summary of Retirements by Scenario, Strategy and Load Growth[70]

	Large Thermal Retirements (last year in service shown)								
Case ID	AES 1 & 2	Aguirre Steam 1 & 2	Aguirre CC 1 & 2	Costa Sur 5 & 6	EcoEléctrica	Palo Seco 3 & 4	San Juan 5 & 6	San Juan 5 & 6 Conv	San Juan 7 & 8
S1S2B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2019 2 - 2020	5 - 2020 6 - 2022	Not Retired	3 - 2021 4 - 2023	5 - 2019 6 - 2019	6 - 2033	7 - 2021 8 - 2023
S1S2H	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2020 2 - 2020	5 - 2034 6 - 2020	Not Retired	3 - 2022 4 - 2023	5 - 2019 6 - 2019	6 - 2035	7 - 2023 8 - 2023
S1S2L	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2020 2 - 2021	5 - 2020 6 - 2020	Not Retired	3 - 2023 4 - 2021	5 - 2019 6 - 2019	5 - 2037 6 - 2030	7 - 2021 8 - 2023
S1S3B	1 - 2027 2 - 2027	1 - 2020 2 - 2020	1 - 2019 2 - 2020	5 - 2019 6 - 2021	Not Retired	3 - 2022 4 - 2023	5 - 2019 6 - 2019	5 - 2037 6 - 2031	7 - 2021 8 - 2023
S1S2S1B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2019 2 - 2020	5 - 2020 6 - 2022	Not Retired	3 - 2021 4 - 2023	5 - 2019 6 - 2019	6 - 2033	7 - 2021 8 - 2023
S1S2S5B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2019 2 - 2020	5 - 2020 6 - 2022	Not Retired	3 - 2021 4 - 2023	5 - 2019 6 - 2019	6 - 2033	7 - 2021 8 - 2023
S1S2S6B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2019 2 - 2020	5 - 2020 6 - 2022	Not Retired	3 - 2021 4 - 2023	5 - 2019 6 - 2019	6 - 2033	7 - 2021 8 - 2023
S1S2S7B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2020 2 - 2020	5 - 2036 6 - 2021	Not Retired	3 - 2022 4 - 2023	5 - 2023 6 - 2037	N/A	7 - 2022 8 - 2021
S1S1B	1 - 2027 2 - 2027	1 - 2019 2 - 2020	1 - 2021 2 - 2020	5 - 2037 6 - 2031	Not Retired	3 - 2019 4 - 2019	5 - 2019 6 - 2019	5 - 2036 6 - 2035	7 - 2019 8 - 2019
S3S2B	1 - 2027 2 - 2027	1 - 2019 2 - 2023	1 - 2020 2 - 2020	5 - 2021 6 - 2019	2024	3 - 2021 4 - 2023	5 - 2034 6 - 2020	5 - 2033 6 - 2030	7 - 2023 8 - 2020
S3S2H	1 - 2027 2 - 2027	1 - 2020 2 - 2020	1 - 2019 2 - 2019	5 - 2021 6 - 2021	2024	3 - 2022 4 - 2023	5 - 2021 6 - 2023	5 - 2033 6 - 2029	7 - 2023 8 - 2020
S3S2L	1 - 2027 2 - 2027	1 - 2021 2 - 2021	1 - 2019 2 - 2019	5 - 2020 6 - 2020	2024	3 - 2023 4 - 2021	5 - 2019 6 - 2023	5 - 2032 6 - 2029	7 - 2019 8 - 2021

[70] See Part 5 – Resource Needs Assessment for a detailed description of the various Scenarios.

	Large Thermal Retirements (last year in service shown)								
Case ID	AES 1 & 2	Aguirre Steam 1 & 2	Aguirre CC 1 & 2	Costa Sur 5 & 6	EcoEléctrica	Palo Seco 3 & 4	San Juan 5 & 6	San Juan 5 & 6 Conv	San Juan 7 & 8
S3S3B	1 - 2027 2 - 2027	1 - 2021 2 - 2020	1 - 2019 2 - 2019	5 - 2020 6 - 2021	2024	3 - 2022 4 - 2023	5 - 2022 6 - 2023	5 - 2033 6 - 2030	7 - 2020 8 - 2019
S3S2S5B	1 - 2027 2 - 2027	1 - 2019 2 - 2023	1 - 2020 2 - 2020	5 - 2021 6 - 2019	2024	3 - 2021 4 - 2023	5 - 2034 6 - 2020	5 - 2033 6 - 2030	7 - 2023 8 - 2020
S3S2S8B	1 - 2027 2 - 2027	1 - 2019 2 - 2023	1 - 2020 2 - 2020	5 - 2021 6 - 2019	2024	3 - 2021 4 - 2023	5 - 2034 6 - 2020	5 - 2033 6 - 2030	7 - 2023 8 - 2020
S4S2B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2025	5 - 2020 6 - 2020	2024	3 - 2025 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S2H	1 - 2027 2 - 2027	1 - 2020 2 - 2019	1 - 2025	5 - 2029 6 - 2020	2024	3 - 2025 4 - 2025	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S2L	1 - 2027 2 - 2027	1 - 2020 2 - 2019	1 - 2025 2 - 2032	5 - 2019 6 - 2020	2024	3 - 2021 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S2S9B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2025	5 - 2020 6 - 2020	Not Retired	3 - 2025 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S3B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2029	5 - 2020 6 - 2020	2024	3 - 2022 4 - 2023	5 - 2019 6 - 2019	5 - 2036 6 - 2032	7 - 2021 8 - 2023
S4S2S1B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2025	5 - 2020 6 - 2020	2024	3 - 2025 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S2S4B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2033	5 - 2020 6 - 2024	2024	3 - 2021 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2019 8 - 2019
S4S2S5B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2025	5 - 2020 6 - 2020	2024	3 - 2025 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S2S6B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2025	5 - 2020 6 - 2020	2024	3 - 2025 4 - 2023	5 - 2019 6 - 2019	6 - 2034	7 - 2023 8 - 2023
S4S1B	1 - 2027 2 - 2027	1 - 2020 2 - 2019	1 - 2032 2 - 2025	5 - 2022 6 - 2020	2024	3 - 2019 4 - 2019	5 - 2019 6 - 2019	5 - 2035 6 - 2030	7 - 2019 8 - 2019
S5S1B	1 - 2027 2 - 2027	1 - 2019 2 - 2020	1 - 2033 2 - 2025	5 - 2020 6 - 2019	2024	3 - 2023 4 - 2022	5 - 2019 6 - 2019	5 - 2031 6 - 2026	7 - 2023 8 - 2021
S5S1S5B	1 - 2027 2 - 2027	1 - 2019 2 - 2020	1 - 2033 2 - 2025	5 - 2020 6 - 2019	2024	3 - 2023 4 - 2022	5 - 2019 6 - 2019	5 - 2031 6 - 2026	7 - 2023 8 - 2021

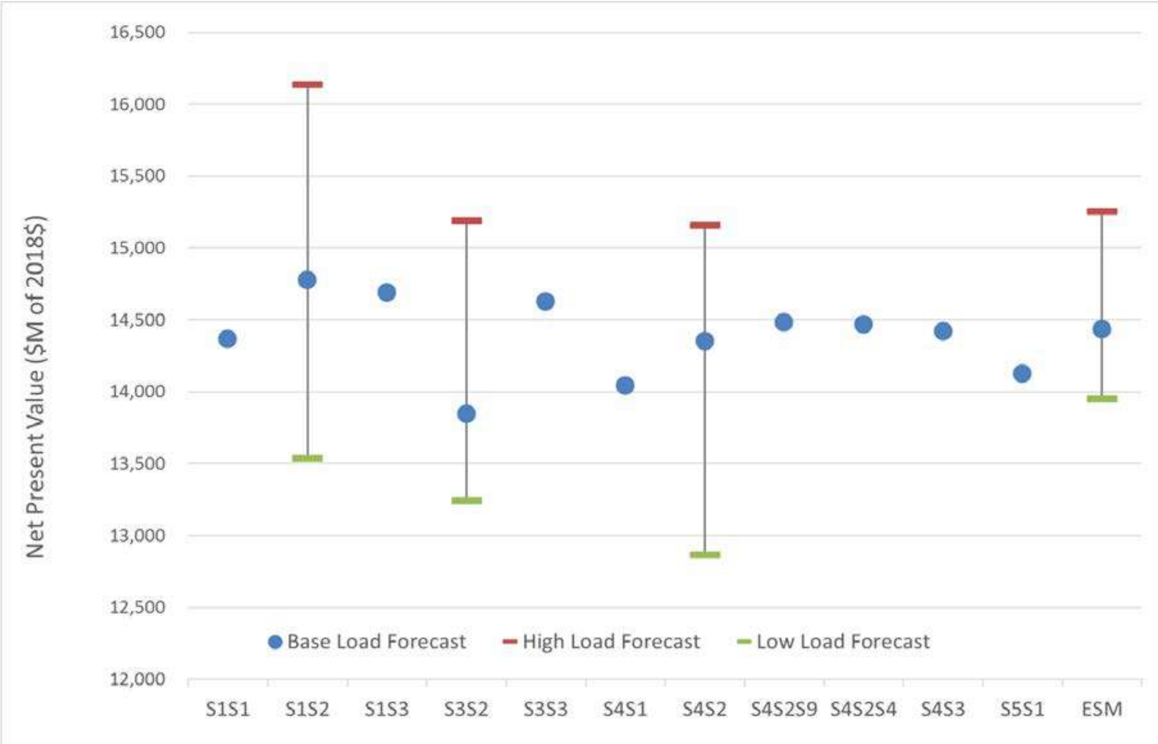
	Large Thermal Retirements (last year in service shown)								
Case ID	AES 1 & 2	Aguirre Steam 1 & 2	Aguirre CC 1 & 2	Costa Sur 5 & 6	EcoEléctrica	Palo Seco 3 & 4	San Juan 5 & 6	San Juan 5 & 6 Conv	San Juan 7 & 8
S5S1S1B	1 - 2027 2 - 2027	1 - 2019 2 - 2020	1 - 2033 2 - 2025	5 - 2020 6 - 2019	2024	3 - 2023 4 - 2022	5 - 2019 6 - 2019	5 - 2031 6 - 2026	7 - 2023 8 - 2021
S5S1S6B	1 - 2027 2 - 2027	1 - 2019 2 - 2020	1 - 2033 2 - 2025	5 - 2020 6 - 2019	2024	3 - 2023 4 - 2022	5 - 2019 6 - 2019	5 - 2031 6 - 2026	7 - 2023 8 - 2021
ESM	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2032	5 - 2020 6 - 2020	Not Retired	3 - 2025 4 - 2025	5 - 2019 6 - 2019	5 - 2035 6 - 2025	7 - 2023 8 - 2021
ESM High	1 - 2027 2 - 2027	1 - 2022 2 - 2019	1 - 2025 2 - 2025	5 - 2021 6 - 2020	Not Retired	3 - 2025 4 - 2021	5 - 2019 6 - 2019	5 - 2036 6 - 2025	7 - 2025 8 - 2022
ESM Low	1 - 2027 2 - 2027	1 - 2025 2 - 2025	1 - 2025 2 - 2028	5 - 2020 6 - 2020	Not Retired	3 - 2022 4 - 2025	5 - 2019 6 - 2019	5 - 2033 6 - 2025	7 - 2021 8 - 2025
ESMS1B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2032	5 - 2020 6 - 2020	Not Retired	3 - 2025 4 - 2025	5 - 2019 6 - 2019	5 - 2035 6 - 2025	7 - 2023 8 - 2021
ESMS6B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2032	5 - 2020 6 - 2020	Not Retired	3 - 2025 4 - 2025	5 - 2019 6 - 2019	5 - 2035 6 - 2025	7 - 2023 8 - 2021
ESMS5B	1 - 2027 2 - 2027	1 - 2019 2 - 2019	1 - 2025 2 - 2032	5 - 2020 6 - 2020	Not Retired	3 - 2025 4 - 2025	5 - 2019 6 - 2019	5 - 2035 6 - 2025	7 - 2023 8 - 2021

Exhibit 1-3: Summary of Results by Scenario, Strategy and Load Growth

	Central Metrics							
Case ID	**NPV @ 9% 2019-2038 k$**	**Average 2019-2028 2018$/MWh**	**RPS 2038**	**NPV Deemed Energy Not Served k$ (1)**	**NPV + ENS k$**	**Lowest Reserve Margin**	**Emissions Reductions**	**Capital Investment Costs ($ Millions)**
S1S2B	14,773,629	102.2	54%	214,355	14,941,402	38%	96%	5,840
S1S2H	16,134,592	101.4	68%	392,504	16,527,096	36%	94%	5,857
S1S2L	13,535,576	101.3	68%	263,997	13,799,572	37%	99%	4,684
S1S3B	14,687,535	101.8	54%	485,666	15,173,201	33%	97%	5,560
S1S2S1B	14,449,784	100.1	54%	214,355	14,617,557	38%	96%	5,293
S1S2S5B	15,378,227	106.0	54%	214,355	15,546,000	38%	96%	5,840
S1S2S6B	16,018,738	110.2	54%	214,355	16,186,511	38%	96%	7,898
S1S2S7B	15,696,705	106.8	68%	422,543	16,119,248	44%	96%	6,606
S1S1B	14,366,811	98.4	68%	1,150,508	15,517,319	35%	96%	5,546
S3S2B	13,843,500	96.4	87%	205,871	14,049,371	48%	97%	8,474
S3S2H	15,191,427	97.3	68%	475,629	15,667,056	36%	92%	8,716
S3S2L	13,242,760	99.6	68%	303,185	13,545,945	47%	96%	7,851
S3S3B	14,627,724	99.8	68%	202,994	14,830,718	30%	92%	8,396
S3S2S5B	14,811,928	102.0	87%	205,871	15,017,799	48%	97%	8,474
S3S2S8B	14,357,561	99.2	87%	205,871	14,563,432	48%	97%	9,467
S4S2B	14,350,195	99.3	68%	247,445	14,597,640	42%	86%	6,595
S4S2H	15,254,859	97.0	53%	391,816	16,087,374	60%	91%	5,585
S4S2L	12,865,937	96.5	77%	198,037	12,866,033	33%	89%	5,321
S4S2S9B	14,480,364	99.6	68%	267,841	14,748,205	51%	94%	6,265

	Central Metrics							
Case ID	**NPV @ 9% 2019-2038 k$**	**Average 2019-2028 2018$/MWh**	**RPS 2038**	**NPV Deemed Energy Not Served k$ (1)**	**NPV + ENS k$**	**Lowest Reserve Margin**	**Emissions Reductions**	**Capital Investment Costs ($ Millions)**
S4S3B	14,416,274	99.9	54%	279,349	14,695,623	37%	82%	6,188
S4S2S1B	14,012,096	97.4	68%	247,445	14,259,541	42%	86%	5,961
S4S2S4B	14,466,325	100.9	65%	345,809	14,812,134	34%	84%	6,552
S4S2S5B	15,255,494	104.8	68%	247,445	15,502,939	42%	86%	6,595
S4S2S6B	15,565,108	106.7	68%	247,445	15,812,553	42%	86%	8,756
S4S1B	14,039,431	97.9	68%	1,108,890	15,148,321	47%	88%	6,674
S5S1B	14,122,690	98.4	67%	593,173	14,715,863	32%	87%	6,201
S5S1S5B	15,660,368	110.0	67%	593,173	16,253,541	32%	87%	6,201
S5S1S1B	13,813,169	96.4	67%	593,173	14,406,342	32%	87%	5,697
S5S1S6B	15,335,600	106.4	67%	593,173	15,928,773	32%	87%	8,165
ESM	14,431,214	99.0	67%	266,947	14,698,161	53%	88%	5,556
ESM High	15,695,558	99.2	53%	391,816	16,087,374	60%	91%	5,763
ESM Low	13,952,366	105.0	54%	202,453	14,154,819	58%	91%	4,779
ESMS1B	14,121,243	97.1	67%	266,947	14,121,340	53%	88%	5,556
ESMS6B	15,592,035	106.3	67%	266,947	15,592,141	53%	88%	5,556
ESMS5B	15,612,073	106.9	67%	266,947	15,612,180	53%	88%	5,556

Exhibit 8-4: Summary Scenarios with load sensitivity



As can be seen in prior table and chart above, Scenario 3 Strategy 2 (S3S2) provides the lowest NPV ($13.8) NPV for the base load forecast but has higher costs than Scenario 4 Strategy 2 for the low load forecast and about the same to S4S2 and the ESM for the high load forecast. This plan assumes a deeper reduction in the cost of renewable and storage (using the NREL Low for PV) and may not be realized. However, this plans may have practical implementation issues given that the amounts of PV output over the long term is almost double the forecasted peak load (4140 MW of new PV over less than 1,800 MW of peak load by 2038). During periods of light load the PV output would be an even higher multiple of forecasted load. This large renewable capacity would strain the remaining resources on the system including the storage and could lead to unexpected curtailment. For this reason, we see this case as a guide to potential enhancements that can be considered if both the cost of PV declines faster than the base case and greater amounts of renewable can be safely operated. Another issue identified with this plan is the management of the curtailment; after several rounds of adjustments of the installed Storage we were able to reduce the curtailment to under 2% for the relevant period 2019 to 2028 but remained over 10% for the remaining of the planning period. Also note that as S3S3 resulted in a higher NPV than S3S2 before adjustments, we did not conduct these adjustments and hence the case has much higher curtailment (7% and 35%) and the NPV above is before adjustment. In summary Scenario 3 is not considered the preferred portfolio due to its assumed deep reduction in renewable prices and the risk of managing the implied amount of renewable generation and storage.

Scenario 4 Strategy 1 (S4S1) and Scenario 5 Strategy 1 (S5S1) and provides the second and third lowest NPV results ($14.0B and $14.3B) for the base load forecast. These LTCE plans are based on a centralized strategy and was determined not to the preferred resource

plan, due to the high levels of load shedding that would be required during a major storm that segments the island into the MiniGrids proposed, as was also shown before. The S4S1 plan develops the combined cycle at Yabucoa (2028) and Mayaguez (2025) and S5S1 develops all the new thermal generation at Costa Sur (two larger 369 MW F-class CCGT), all these developments are is contrary to the resiliency requirements. Also, as will be shown next S5S1 is also more sensitive to gas price fluctuations.

Before we enter to discuss what we consider the preferred scenarios, it should be noted that while Scenario 1 Strategy 1 has costs similar to S4S2 and the ESM, this case has some major flaws that make it unadvisable; first it extends both Costa Sur 5&6 until after 2030 as well as EcoEléctrica creating a concentration of generation in the south and resulting in high levels of expected energy not served and has high levels of curtailment in the medium and long term.

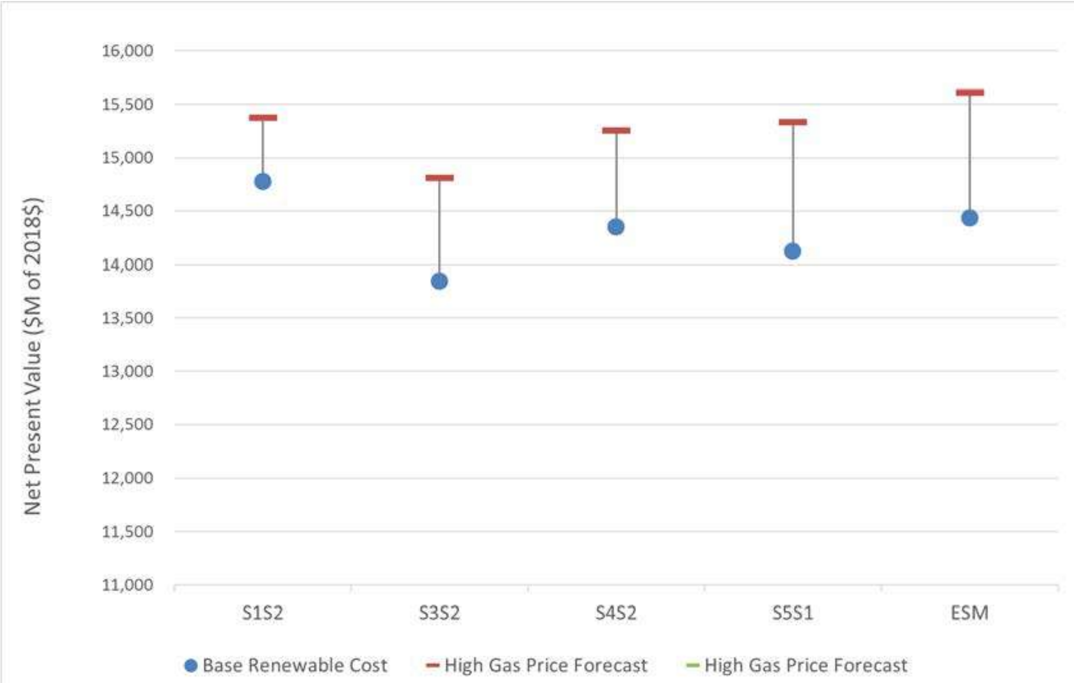
The NPV's of Scenario 4 under Strategy 2 (S4S2) ($14.35) and Scenario 4 under Strategy 3 (S4S3) ($14.41B) are very similar, however Strategy 2 has the lower value as well as the value of deemed energy not served and hence preferred. This case is discussed further below.

The next lowest NPV is the ESM plan ($14.43B) that is compared with Scenario 4 Strategy 2 (S4S2) ($14.35). These plans were determined to be practical and low cost plans that contain the recommended path forward. We also note that the ESM and the S4S2 plans are very similar for the possible high demand case and only deviate from each other under the low demand conditions, where S4S2 that has reduced thermal decisions, would be a better plan.

The ESM and S4S2 contain a common set of no regret / minimum regret elements in the near term plan that were shared by some of the other LTCE plans with favorable results depending on the future conditions. The sensitivity 9 (S4S2S9) that kept EcoEléctrica online on Scenario 4 resulted in an NPV ($14.5B) similar to the above and slightly higher than the ESM's NPV, highlighting the similarity of these plans.

Sensitivity 4 that does not develops the land based LNG at San Juan (S4S2S4) had an NPV ($14.5B) somewhat higher than the cases above. That is the CCGT at San Juan was replaced by more PV generation.

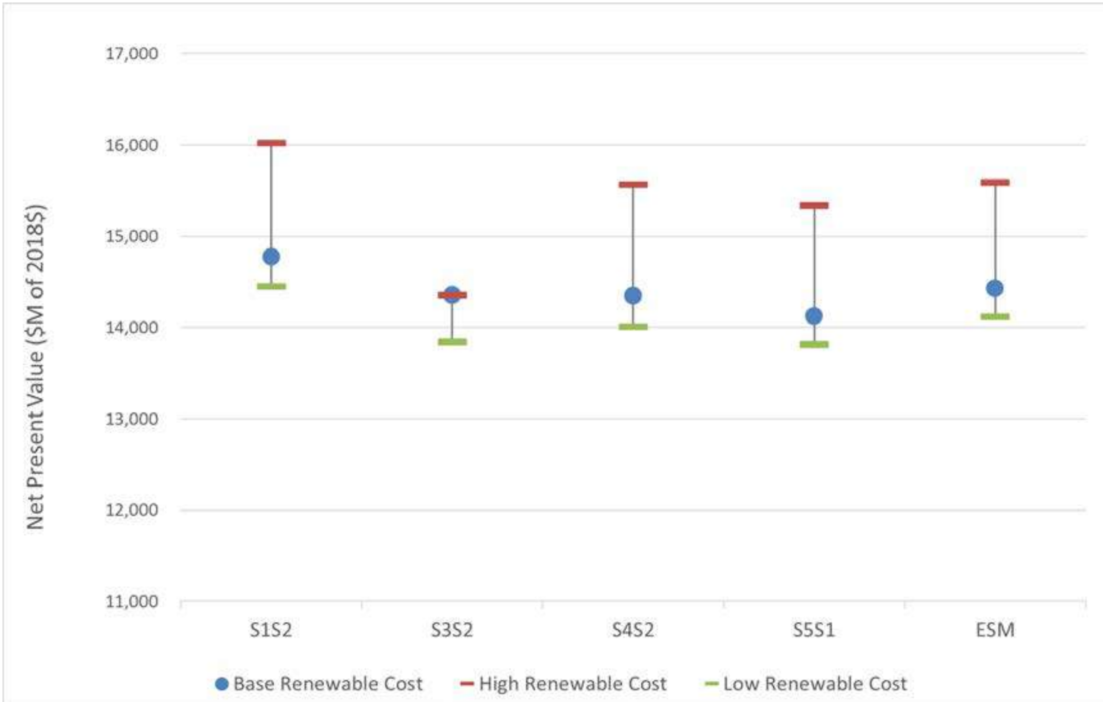
Exhibit 8-5: Summary Scenarios with gas price sensitivity



The exhibit above shows the effect of gas price increase in the various scenarios. As expected, we observe that S1S2 is the least affected (4% increase) but its NPV remains above that of S4S2. Scenario 5 has the greatest sensitivity (9% increase) and its costs go above those of Scenario 4 that has a 6% increase. Finally, the ESM is affected at a level between Scenario 4 and Scenario 5 (8% increase).

Finally, the exhibit below shows the impact of renewable price sensitivity (no changes in the LTCE were made, just increase the capital / O&M costs). As can be observed there is no drastic change on the ranking, however it should be noted that in the case of Scenario 3 the sensitivity was made going from Lowe Renewable Prices to Base.

Exhibit 8-6: Summary Scenarios with renewable price sensitivity



To provide additional views on the comparison between the portfolios, the exhibit below shows as "balanced score card" where the key metrics were normalized so that green is the best outcome and red is the worse. In this exhibit we observe three scenarios that stand out; S1S2B, S4S2B and the ESM. S1S1B has higher NPV and higher expected costs in $/MWh and as will be detailed in this section depends on the use of GT's burning light fuel oil that can reach up to 10% of the generation by the time AES retires. However, this plan has lower capital costs. The lower sensitivity to gas prices is basically due to the fact that there are fewer plants using this fuel. The main issue with this scenario, in addition with the fact that it has higher costs, is that it depends on the use of peaking generation (burning diesel) as mentioned earlier and more storage as the generation at Palo Seco is not developed. S4S2B and the ESM provide a good balance across all metrics as can be observed.

Further we note that S3S2 (that was adjusted as mentioned above) has lower NPV, but the highest capital costs, highest technology risk and high sensitivity to renewable capital costs given the amount of this type of generation developed and Scenario 5 has also low NPV but the high risk for energy not served and high fuel price sensitivity.

Exhibit 8-7: Scorecard for Scenario 1, ESM, Scenario 4 and Scenario 5 for the Reference Scenario (Base Load Growth, Renewable prices and fuel)

	S1S1B	S1S2B	S1S3B	S3S2B	S3S3B	S4S1B	S4S2B	S4S3B	S5S1B	ESM
NPV @ 9% 2019-2038 k$	9.6	9.4	9.4	10.0	9.5	9.7	9.6	9.6	9.8	9.6
Average 2019-2028 2018$/MWh	9.8	9.4	9.5	10.0	9.7	9.7	9.7	9.6	9.8	9.7
Capital Investment Costs ($ Millions)	10.0	9.5	10.0	6.5	6.6	8.9	8.4	9.0	8.9	10.0
NPV Deemed Energy Not Served	1.8	9.5	4.2	9.9	10.0	2.3	8.2	7.3	3.4	7.6
RPS 2038	7.8	6.1	6.1	10.0	7.8	7.8	7.8	6.1	7.7	7.7
Emissions Reductions	9.9	9.9	10.0	10.0	9.4	8.7	8.9	8.5	9.0	9.1
Technology Risk (PV / Max Demand)	10.0	9.3	9.8	6.1	6.1	9.3	8.9	8.9	9.8	9.8
High Fuel Price Sensitivity on NPV		10.0		9.7			9.8		9.4	9.6
High Renewable Cost Sensitivity on NPV		10.0		5.0	5.0		10.0		9.9	10.0
Overall	7.9	8.9	7.3	8.3	8.0	7.0	8.7	8.3	8.2	8.8

For the case of high load growth, we observe below that Scenario 4 Strategy 2 has the best outcomes followed by the ESM. Scenario 1 and Scenario 3 have worse outcomes due to high NPV the first and higher energy not served and particularly the technology risk the second.

Exhibit 8-8: Scorecard for Scenario 1, ESM, and Scenario 4 and Scenario 5 for the High Load Growth Case.

	S1S2H	S3S2H	S4S2H	ESM high
NPV @ 9% 2019-2038 k$	9.4	10.0	10.0	9.7
Average 2019-2028 2018$/MWh	9.5	9.9	10.0	9.8
Capital Investment Costs ($ Millions)	9.6	6.5	10.0	9.8
NPV Deemed Energy Not Served	8.1	6.7	10.0	8.1
RPS 2038	10.0	10.0	8.8	7.8
Emissions Reductions	10.0	9.8	8.6	9.7
Technology Risk (PV / Max Demand)	7.7	5.4	9.8	10.0
Overall	8.5	7.8	9.3	8.9

For low load both the ESM and S4S2 have the best overall results, but the ESM has higher NPV than any of the cases, compensated by lower capital costs results.

Exhibit 8-9: Scorecard for Scenario 1, ESM, and Scenario 4 and Scenario 5 for the Low Load Growth Case.

	S1S2L	S3S2L	S4S2L	ESM Low
NPV @ 9% 2019-2038 k$	9.5	9.7	10.0	9.2
Average 2019-2028 2018$/MWh	9.5	9.7	10.0	9.2
Capital Investment Costs ($ Millions)	10.0	6.0	8.8	9.8
NPV Deemed Energy Not Served	7.5	6.5	10.0	9.8
RPS 2038	8.8	8.8	10.0	7.0
Emissions Reductions	10.0	9.7	9.0	9.3
Technology Risk (PV / Max Demand)	8.5	4.9	7.9	10.0
Overall	8.5	7.4	8.9	8.9

Scenario 3 is not compared in this way as it has lower cost of renewable and would render the comparison invalid, however we address Scenario 3 in the next comparison.

We discuss each of the Scenarios below.

8.2 Scenario 4 Results

The generation portfolio identified as Scenario 4 Strategy 2 (S4S2) result in a plan that meets the criteria of least cost, resilience and viability in terms of installation of solar and battery storage, as well as added resilience and flexibility provided by local thermal generation within the MiniGrids. The Strategy 2 used for the formulation of the portfolio focused on distributed resources, which translate into a requirement that at least 80% of the peak demand needs to be supplied locally. This strategy provides a distributed system of flexible generation and MiniGrids that is more resilient and locates supply resources closer to the customer. The portfolio generation mix was also confirmed to be able to supply the forecasted levels of critical load.

The Scenario 4 considers the option of development of LNG terminals at Yabucoa (east coast) and Mayagüez (west coast) through ship-based LNG. The Scenario also includes gas in the north delivered through land-based LNG at San Juan. The Scenario uses the solar and storage costs and availability based on reference case assumptions.

The following additional assumptions were also included in the simulation of this Scenario:

- Load forecast is assessed at Base, High and Low cases
- The AES PPOA is assumed to expire in 2027 and not renewed as per the conditions in Act 17-2019

- EcoEléctrica is assumed to renew in 2022 with a 53% reduction of the fixed payments. In addition, EcoEléctrica is assumed to be adjusted so it has the increased ability to cycle as required to support the integration of renewables. Please see details under section 4.2.1.5.
- San Juan Units 5 & 6 are converted to gas in June 2019. The cost of the conversion is assumed to be structured as a capacity payment of $5 million on an annual basis per unit ending on 06/30/2024.
- San Juan units are subjected to fuel constraints of delivery to San Juan; ship-based fuel constraints for July 2019-June 2024, and land-based LNG constraints from July 2024 through the end of the forecast period.
- Energy Efficiency programs are assumed to meet the requirement of Act 17-2019, i.e., 2% per year of incremental savings attributable to new energy efficiency programs through 2037, resulting in 36% cumulative energy savings by 2038. As a result, the load under the base case is 35 % below 2019 levels by 2038 and 49% below considering the effects of customer owned generation. Comparing to the February filing, the load is now 20% lower by 2038.
- The Scenario assumes solar and storage costs and availability based on reference case assumptions. New PV installations are limited to 300 MW in 2020 and 600 MW annually thereafter. Storage installations are limited to 40 MW in 2019, 200 MW in 2020 and 600 MW annually thereafter.
- The plan reflects Act 17-2019 with RPS targets of 20% by 2022, 40% by 2025 and 60% renewable penetration by 2040. The new RPS targets are twice as high compared to the previous legislation by 2025, when most solar generation needs to be built. The plan achieved a renewable penetration above the targets starting in the late 2020s with more aggressive reduction in load starting in those years as a result of the cumulative impact from Energy Efficiency savings.
- Improve capacity factors for Wind based on NREL ATB TRG-8, mid case and add this as an option to the LTCE selection and offered as a resource to the Aurora LTCE calculations. New wind turbine generation was not selected under the “mid” case renewable price projections, despite the fact that these resources do have some contribution to the nigh peak (about 20%).
- Any non-renewable generator is modeled as fully depreciated by 2050 and ready for retirement by then, when according to Act-17-2019 Puerto Rico is to be supplied by 100% renewable generation..
- High Efficiency Requirement Fossil Generation - For demonstration of compliance, PREPA check compliance using two requirements:
  - The real levelized costs in $/MWh for new and existing CCGTs staying online meet the 100$/MWh requirement in real 2018 dollars. As indicated, it is generally the expectation that when new or existing CCGTs (namely EcoEléctrica and San Juan 5 & 6 gas conversions) dispatching at capacity factors higher than 60%, the levelized costs of energy is at or below $100/MWh in 2018 terms.
  - In reference to the April 26th Order, PREPA is confirming that at least 60% of the total energy from fossil generation comes from highly efficient units.

- Land based LNG Cost at San Juan sized to the new CCGT F class built in the North at Palo Seco (Bayamon). Siemens evaluated the potential maximum fuel used at the terminal from the new combined cycle plus the San Juan 5&6 conversions to gas. As such, the CapEx required is slightly lower compared to previous simulations. Exhibit 8-6 shows the new capital costs assumptions for all terminals. Exhibit 8-7 illustrates the potential maximum volume at the terminal based on dispatching at maximum capacity the new F Class unit and the San Juan conversions. The LPG option was not included in this analysis as it was not selected in any of prior runs..

Exhibit 8-10: Capital Costs Assumptions LNG Terminals

Infrastructure Option	CAPEX $MM (2018$)	Annual OPEX $MM (2018$)	Max Daily Gas Volume (MMcf/d)	Max Gas Volume (MMBtu/month)	Max Capacity MW	CAPEX $/kW (2018$)	Annual OPEX $/kW (2018$)	CAPEX + Annual OPEX $/kW (2018$)
Land-based LNG at San Juan Port (w/o pipeline)	$ 471.62	$ 24.52	125.9	3,924,711	702	68	35	103
Ship-based LNG at Mayaguez (west)	$ 185.00	$ 9.62	53.4	1,642,116	302	62	32	94
Ship-based LNG at Yabucoa (east)	$ 185.00	$ 9.62	53.4	1,642,116	302	62	32	94
Ship-based LNG (FSRU) at San Juan Port (supply to San Juan only)	$ 185.00	$ 9.62	50.4	1,549,815	350	54	27	81

Exhibit 8-11: Maximum Fuel Usage

	San Juan 5 Peak Fuel Consumption	San Juan 6 Peak Fuel Consumption	F-Class Consumption	Total
Capacity	200	200	302	702
Capacity Factor (used to determine peak consumption)	100%	100%	100%	100%
Heat Rate BTU/kWh	7625	7853	7552	
Fuel MMCf/day	35.7	36.8	53.4	125.9
Max Gas Volume (MMBtu/month)	1,113,250	1,146,538	1,664,923	3,924,711

- PREPA can buy RECs to meet the RPS requirements from DG, however as the prices of DG REC's are unknow at this time; RPS compliance was achieved with . utility scale renewable generation only. Future calculations could be done to estimate a value of these RECs.

- The CCGT offered as an option to the LTCE at Costa Sur was assumed to burn natural gas priced under the same conditions from a new ship-based LNG terminal. This consideration makes the selection of this CCGT independent of any assumptions with respect of the costs of the gas to be delivered from the Costa Sur LNG terminal.

As indicated in Part 5, the Scenario 4 was evaluated considering three load growth levels (low, base and high) and two strategies (2 and 3). Strategy 1 with the base load growth was also considered as well as two sensitivities; a ship based LNG terminal in San Juan (sensitivity 4) and high cost of gas (sensitivity 5). Exhibit 8-12 has a summary of the generation expansion under all cases considered for Scenario 4 that will be discussed in further detail in the next sections. As can be observed there is significant agreement on results, which can be used to identify the preferred robust decisions; i.e. those that would minimize the regret should future conditions be different than those anticipated in the assumptions (e.g. higher or lower load, etc.).

Exhibit 8-12. Scenario 4 Summary of results

					Large & Medium CCGTs and Peakers							Renewable and Storage				
Case ID	Scenario	Strategy	Sensitivity	Load	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peker Conversion	Other	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)	Customer Owned Generation 2038 (MW)
S4S2B	4	2		Base	✔	✔	✔	–	–	–	371	2,220	1,320	2,820	1,640	1,176
S4S2H	4	2		High	✔	✔	✔	–	–	–	394	2,460	940	2,520	980	1,176
S4S2L	4	2		Low	–	✔	✔	–	–	–	434	2,100	960	2,520	1,020	1,176
S4S2S9B	4	2	9	Base	✔	EcoEléctrica Instead	✔	–	–	–	348	2,220	1,320	2,820	1,640	1,176
S4S3B	4	3		Base	2027	✔	✔	–	–	–	394	2,580	1,320	2,820	1,320	1,176
S4S2S1B	4	2	1	Base	✔	✔	✔	–	–	–	371	2,220	1,320	2,820	1,640	1,176
S4S2S4B	4	2	4	Base	–	✔	✔	–	–	–	371	2,580	1,320	3,060	1,640	1,176
S4S2S5B	4	2	5	Base	✔	✔	✔	–	–	–	371	2,220	1,320	2,820	1,640	1,176
S4S2S6B	4	2	6	Base	✔	✔	✔	–	–	–	371	2,220	1,320	2,820	1,640	1,176
S4S1B	4	1		Base	–	–	✔	2028	–	F-Class at Mayguez 2025	348	2,700	1,240	2,700	1,640	1,176

8.2.1 Capacity Additions and Retirements

The economic simulation of Scenario 4 under strategy 2 results in 2,820 MW of utility scale PV additions over the study period with the first 300 MW added in 2020. A total of 1,380 MW is added in the first four years of the plan in 2019-2022, which is consistent across the high and low load cases; (see Exhibit 8-8). The amount of solar is 24% higher compared to the 2,220 MW reported in the February filling for Scenario 4 due to the much higher renewable targets under Act 17-2019.

The analysis of S4S2 and its sensitivities indicates that the recommendation to build at least 1,380 MW of solar in the short to medium-term in Puerto Rico, is robust (minimum regret) regardless of the capital costs for solar photovoltaic in order to meet the RPS targets of 15% and 20% in 2021 and 2022, respectively, and that PREPA is able to contract for and interconnect this high level of new solar PV additions.

The recommendation under the February filling by PREPA was to develop 1,200 MW of solar in 2019-2022. However, the new RPS targets mandated by Act 17-2019 demands a larger development of solar PV in the short to medium term. If the capital costs for solar photovoltaic results to be higher or lower than forecast, the amount of solar installations would not materially change in order to meet the RPS Targets of 15% and 20% in 2021 and 2022, respectively. In all scenarios, nearly 1,400 MW of solar PV are needed to meet the RPS targets by 2022 and 2,220 MW by 2025. In the long-term the amount of solar installed may increase with lower capital costs or otherwise with higher capital costs. Under PREB order from April 2019, the Bureau asked PREPA to run scenarios around high and low renewable capital costs without changing the expansion plan in the base case under Strategy 2 [71]. The results are discussed in section 8.2.11 Sensitivity Considerations.

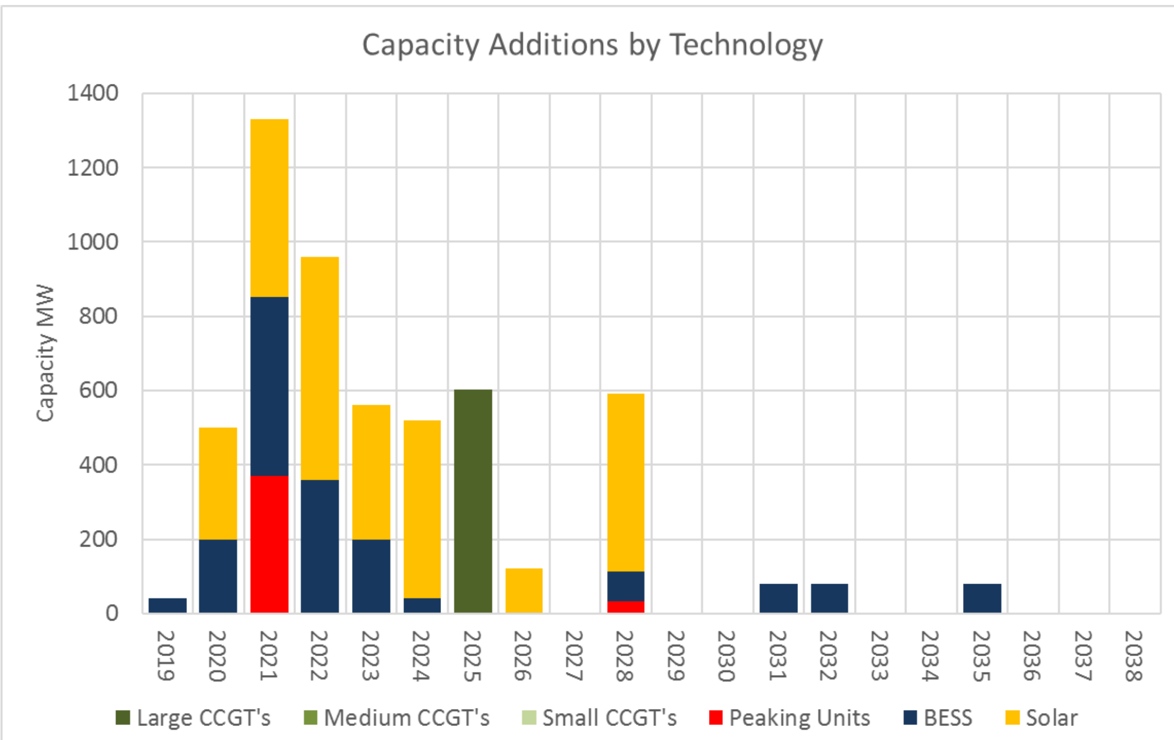
In Scenario 4 base load, 1,640 MW of battery energy storage is built over the study period, with 1080 MW in 2019-2022 and 1,320 by 2025, about 80% of the total. In the high and low load cases, 980 to 1,020 MW of storage is built, respectively, over the study period with most

[71] The PREB asked PREPA to run scenarios based on the Strategy with lower NPV costs under base load. Strategy 2 was found to have lower system costs for Scenario 4.

of the capacity built by 2025 (see Exhibit 8-12). A robust decision is to build a minimum of 1000 MW of storage by 2025, with the expected storage capital prices. The amount of storage built over the study period is 51% higher compared to the 1,080 MW reported in the February filling for Scenario 4, all driven by a larger amount of solar installations in this scenario to meet the new RPS targets. The Siemens team performed a detailed simulation of the cases finding that an enhanced amount of storage was needed to support the renewables and reduced curtailments and system costs. The ratio of storage to solar is 58% under the base case load with a lower ratio needed in the high and low load cases at 40%.

However, since the benefits of the battery energy storage are largely drawn from its support of renewables, should installations of renewables be less than expected, it may be desirable to slow the addition of the energy storage so that it better aligns with the rate of renewable additions.

Exhibit 8-13:S4S2 Portfolio Base Load Forecast Capacity Additions



No wind turbine generation was built by the plan, in either the base load or the high and low load cases.

Two large F-Class CCGT units are installed (302 MW each for a total of 604 MW), one in Palo Seco (Bayamon) and the other in (Ponce West) at Costa Sur, both in 2025. In addition, there is 371 MW of new gas peaker capacity, mostly mobile peakers included in the scenario by design to support the mini-grid operations. Only one peaker of 23 MW was built economically by the model. Total capacity additions include the conversions of San Juan units 5 & 6 to natural gas in 2019.

In the prior filling in February, a total of three large F-Class CCGTs were installed (906 MW in total) under the base load forecast, one in Palo Seco (Bayamon) in 2025, another in Costa Sur (Ponce West) in 2025, and an additional CCGT in Mayagüez in 2028, after AES retirement.

In the updated evaluations with lower load due to energy efficiency and higher RPS mandates, only one CCGT is developed in addition to the new CCGT in Costa Sur (or the renegotiation of EcoEléctrica). Under Strategy 2, that resulted in lower NPV of total generation costs than Strategy 3, this new CCGT is developed at Palo Seco by 2025 (or as soon as practical) and under Strategy 3 it is developed in the same place but by 2027.

Under Strategy 2 for the high load case, the two F-Class CCGT units in Palo Seco and Ponce West are also installed by 2025. In contrast, in the low load case, the F-Class at Palo Seco is not installed, only the F-Class in Costa Sur in 2025.

The high and low load scenarios were not developed for Strategy 3 this time per PREB's order[72].

The F-Class CCGT at Palo Seco is not developed in any other scenario that considered a land-based LNG terminal developed at San Juan with a pipeline connecting to the Palo Seco plant; in other words, the F-Class at Palo Seco is not developed under Scenario 3 and Scenario 5 under any load case; however as mentioned earlier Scenario 5 has resiliency concerns as it develops all the new thermal at Costa Sur and Scenario 3 has implementation issues due to the large amount of PV that would be required as compared with the load served.

Under Scenarios 3 and 5 a new CCGT is also developed at Costa Sur by 2025 assuming that no agreement is reached with EcoEléctrica. Under Scenario 5, one larger F-Class CCGT (369 MW) is built instead of a small F class (302 MW), by 2025. In addition, in Scenario 5, an additional larger F-class CCGT is developed in 2028 in Costa Sur.

The decision to build an F-Class CCGT in Costa Sur is least cost, with the only caveat that should the renegotiation of the EcoEléctrica supply agreement yield a new agreement with lower fix payments and higher dispatch flexibility, it could be possible to avoid the need for the F-Class CCGT at Costa Sur and maintain EcoEléctrica instead. Thus, a minimum regret decision is to advance both processes in parallel; the CCGT at Costa Sur and the negotiation with EcoEléctrica.

In addition, Scenario 4 calls for 371 MW of peaking generation by 2025 (all natural gas) with an additional 32 MW built economically in 2028. Most of this generation is required to cover critical loads and provide MiniGrid resiliency (Carolina, Caguas, Ponce East (Jobos), Cayey and Mayagüez North).

As discussed previously, San Juan 5 & 6 are converted to gas in 2019. San Juan 6 is then retired by 2034 due to economics.

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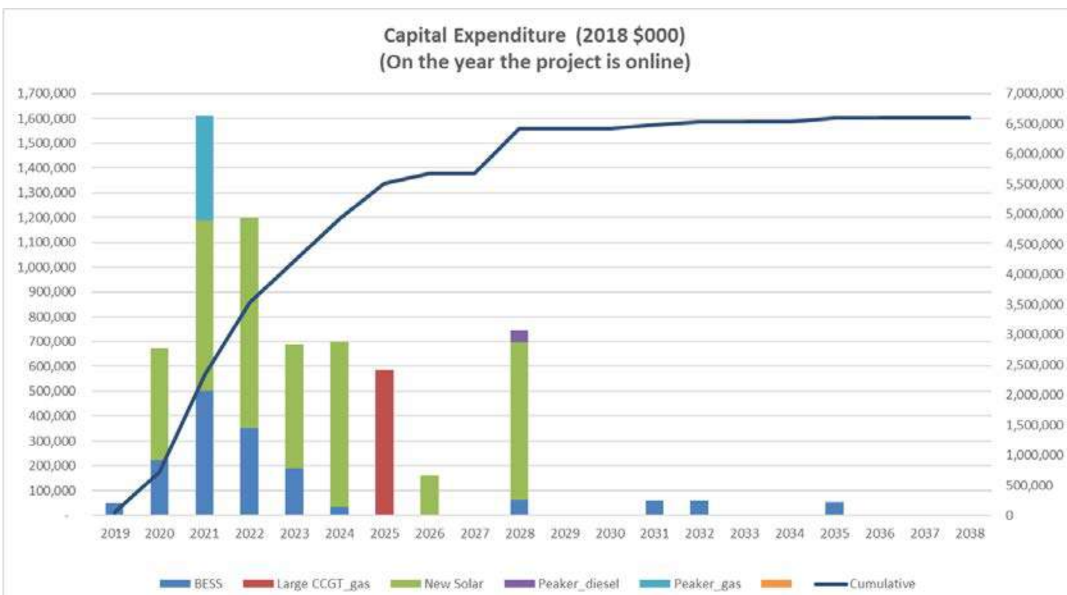
[72] The PREB asked PREPA to run scenarios based on the Strategy with lower NPV costs under base load. Strategy 2 was found to have lower system costs for Scenario 4.

Compared to the February filling, the F-class CCGT at Mayaguez is not built, primarily due to the lower demand forecast. The only exception is Strategy 1 that instead of Costa Sur and Palo Seco, develops Mayaguez in 2025 and Yabucoa in 2028, but this case is less resilient than Strategy 2 or 3 and has only slightly lower NPV.

8.2.2 Capital Expenditures

While expressed as capital expenditures, we assumed that all new generation would be acquired though an RFP process for PPOAs and hence the capital investments will be made by developers and covered in a fixed charge calculated using the WACC and the economic life. The figure below shows the levels of capital expenditures required for the S4S2 Portfolio under the Base Load forecast. These capital costs are all in and include interest during construction but are expressed as a single capital expenditure in the year the plants come online (also known as overnight capital costs). We observe that the largest investment is required for the generation assets expected to be in service in 2021 ($1.6 billion), for new solar, peaking generation and storage. Total capital investments reach $ 6.6 billion (US$ 2018) by 2038.

Exhibit 8-14: S4S2 Portfolio Base Load Forecast Capital Expenditure



CapEx $000 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
BESS	49,213	224,122	504,364	353,399	188,956	36,365	-	-	-	64,507
Large CCGT_gas	-	-	-	-	-	-	585,827	-	-	-
New Solar	-	451,884	685,584	847,619	502,679	663,084	-	161,911	-	632,234
Peaker_diesel	-	-	-	-	-	-	-	-	-	49,540
Peaker_gas	-	-	419,024	-	-	-	-	-	-	-
Grand Total	**49,213**	**676,006**	**1,608,972**	**1,201,018**	**691,635**	**699,449**	**585,827**	**161,911**	**0**	**746,281**

8.2.3 Capacity Retirements

The installation of the PV and Storage in 2020, together with the long-term reduction in demand allows for the economic retirement of Aguirre ST 1 and 2 (end of 2019), Palo Seco ST 3 and 4 are retired by the end of 2024 and San Juan Steam units 7 & 8 end of 2023. Palo

Seco Steam units are retired by the end of 2024 due to the entry in 2025 of the new combined cycle at Palo Seco.

Even under high load conditions, the Aguirre steam units are retired by the end of 2020, but the San Juan 7&8 units and Palo Seco 3&4 retired as well in 2023 and 2024, respectively. Under low load conditions, the Palo Seco units retired earlier in 2021 and 2023.

It is important to indicate that the dates above are in reality indication of the conditions when the generation could be retired; for example, a retirement by the end of 2019, implies that the new generation that will support the retirement must be online by that time (i.e. January 2020) as well as the projected load levels.

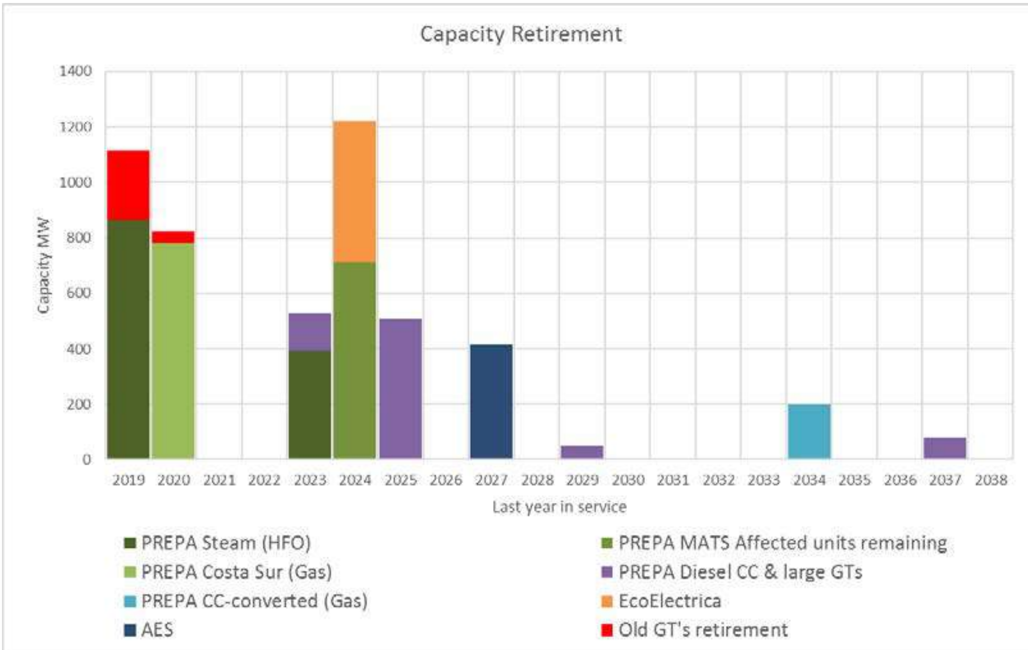
EcoEléctrica is economically retired by the end of 2024, in spite of the reduction in the fixed payments of 53%, and assuming the unit has more flexibility by allowing it to cycle on a weekly basis. This retirement is triggered by the entry of a new CCGT at Costa Sur (F-Class) and happens irrespective of the load forecast. As will be discussed below a sensitivity was run that identified that a reduction of the fixed payments by 60% (instead of 53%) would have been sufficient for breakeven under the base load forecast.

Costa Sur 5 & 6 last year in service is 2020 as it could not compete with EcoEléctrica, under the base load and low load forecast. Under the high load case, one of the units stays online longer until the end of 2029.

Both Aguirre CC units 1 and 2 are retired in 2025. Cambalache units 2 & 3 retire in 2023 and 2037, respectively. Two of the Aero Mayagüez peakers are retired in 2023 and 2029 and two stay online for local reserves to the end of the forecast. On the low load forecast the decision is similar regarding the Aero Mayagüez units with two (at least 100 MW) staying online for local reserves to the end of the forecast. In the high load forecast, the two units retired are decommission later in 2030 and 2036. It should be indicate that in the case of the gas turbines and depending on its condition it may be advisable to mothball them allowing to be brought online if necessary for MiniGrid operations (i.e. when the main grid is split into areas).

AES is retired by 2028, not economically but by model input and in line with Act 17-2019.

Exhibit 8-15: Scenario 4 Capacity Retirements (last year in service



S4S2 Base Technology / MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PREPA Steam (HFO)	862	0	0	0	395	0	0	0	0	0
PREPA MATS Affected units remaining						206	1	0	0	0
PREPA Costa Sur (Gas)	0	782	0	0	0	0	0	0	0	0
PREPA Diesel CC & large GTs	0	0	0	0	132	0	506	0	0	0
PREPA CC-converted (Gas)	0	0	0	0	0	0	0	0	0	0
EcoElectrica	0	0	0	0	0	507	0	0	0	0
AES									417	0

Finally, the natural gas converted San Juan 6 is retired by 2034. San Juan 5 remains online under the all load forecasts. Based on the above, it can be concluded that these units are expected to remain online once converted, at least through the end of the decade.

Overall, the steam units running on fuel oil have costs above those of the combination of PV + Storage and their inflexibly would create renewable curtailment, hence al the steam units are retired.

8.2.4 Future Generation Mix and Reserves

As shown in the exhibit below, the system transitions from one based on coal and oil to a system dominated by natural gas, renewables and energy storage. By 2038, 79% of the installed capacity in the system consists of renewable generation or facilities in place for its integration, including solar, battery storage and CHP distributed generation. Total renewable generation accounts for 63% of the total by 2038 with gas generation accounting for 30% of the total (Exhibit 8-13). Most of the gas generation comes from the two new large CCGTs and San Juan conversions. As such, the development of the LNG terminals is critical to reach the full potential of the new gas units.

As PREPA's units and the thermal PPOA's are phased out, the operating reserves decline from 87% in 2023 to a low of 41% by 2028 with the retirement of AES. Operating reserves rise afterwards driven by the large decline in load and the addition of 320 MW in storage and 32 MW of peakers in the last ten years. The Planning Reserve Margin of 30% appears not to have been binding constraint on the LTCE plan formulation in this Scenario with the reserve margin of at minimum 41% through the forecast.

Exhibit 8-16: Scenario 4 Installed Capacity Mix

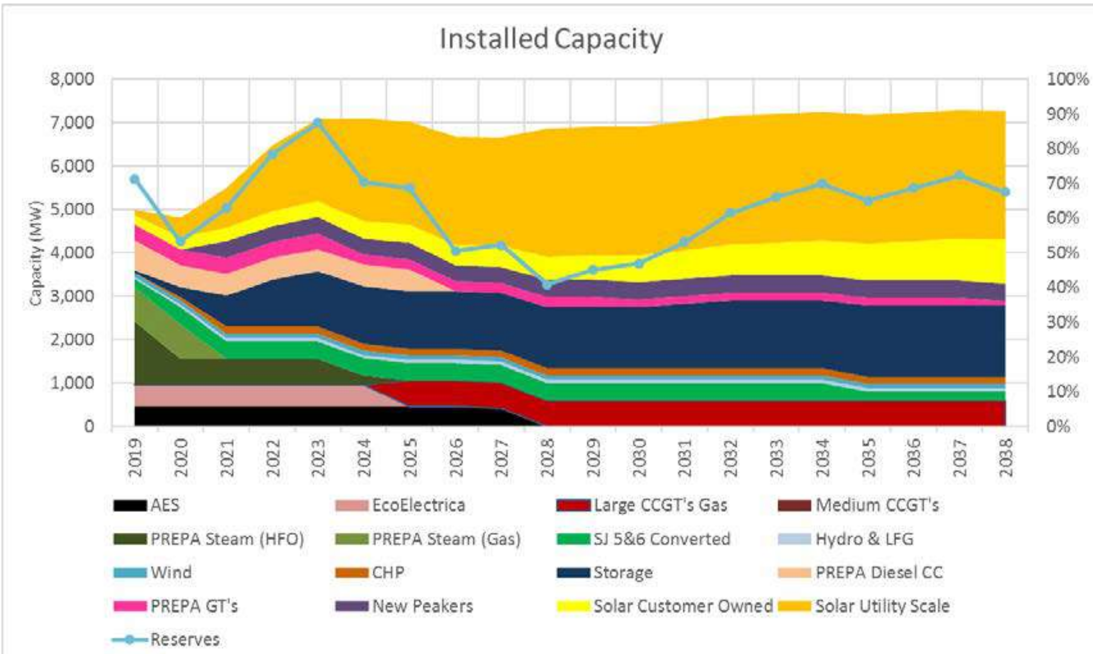
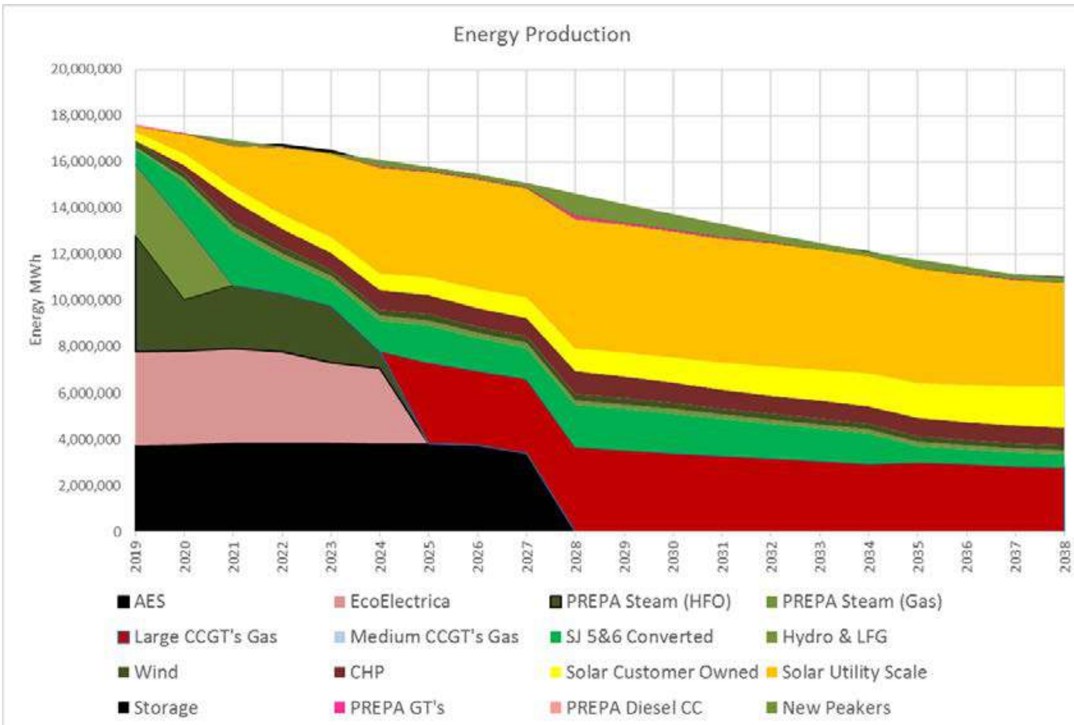


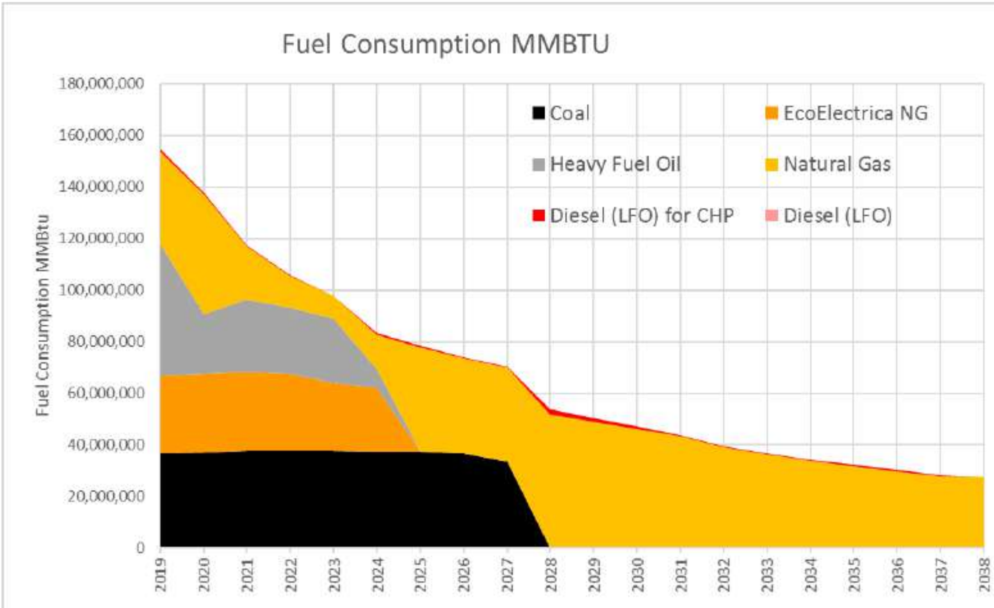
Exhibit 8-17: Scenario 4 Future Generation Production Mix



8.2.5 Fuel Diversity

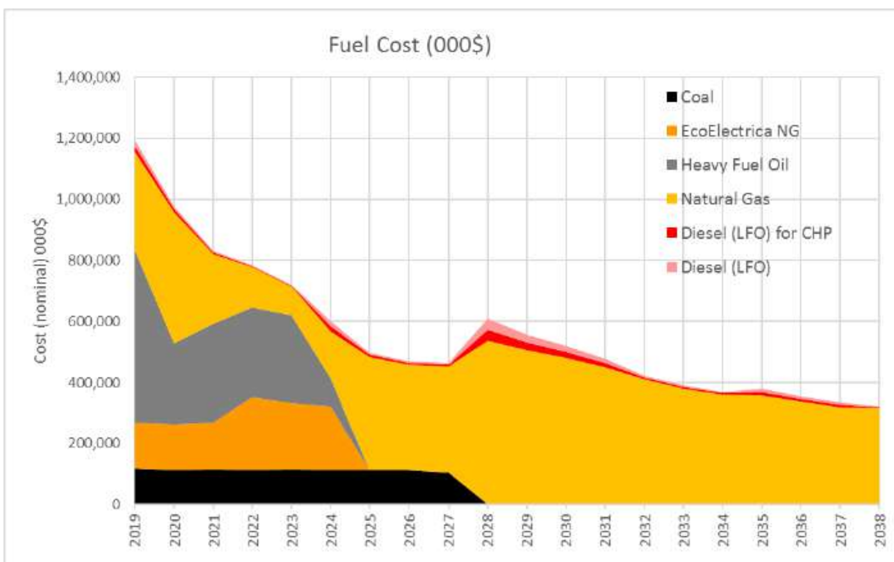
In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas along with a sharp drop in overall fuel consumption and associated costs with the implementation of the plan. Fuel consumption declines with the retirement of EcoEléctrica in 2024, old gas and heavy fuel oil units and the peakers. Overall fuel consumption continues to fall through 2038 despite the new CCGTs in Palo Seco and Costa Sur coming online in 2025. Total fuel consumption drops 82% by 2038 with natural gas dominating this remaining fuel consumption.

Exhibit 8-18: Scenario 4 Fuel Consumption Trends



Fuel costs decline 73% through the study period in line with the fall in fuel consumption to $319 million by 2038. Fuel costs are 35% lower in the long-term compared to the February filling due to lower demand and the decision for not building the Mayaguez CCGT under the new plan.

Exhibit 8-19: Scenario 4 Fuel Costs

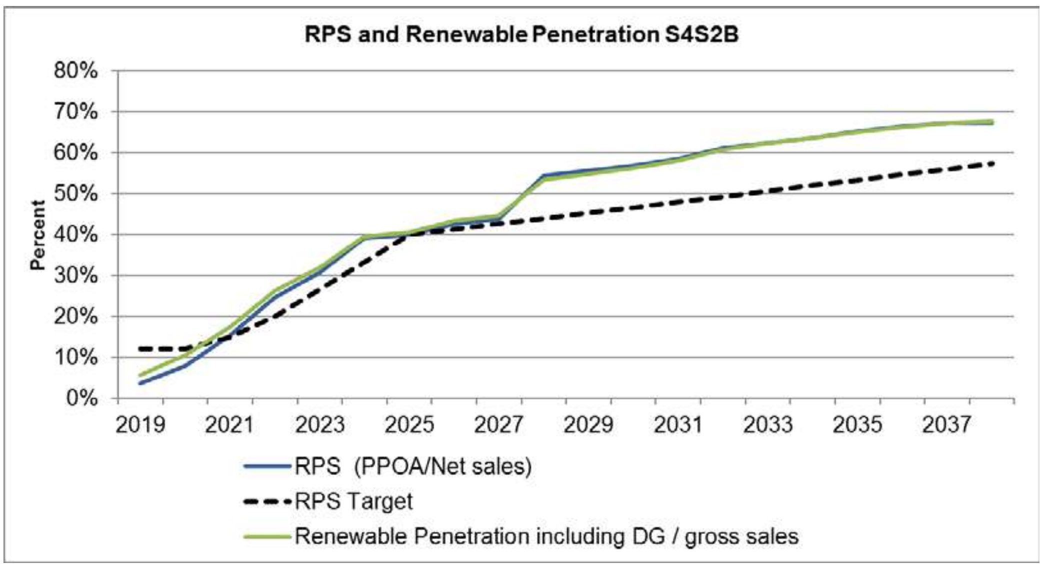


8.2.6 RPS and Environmental Compliance

The Scenario 4 plan is MATS compliant after 2024 and achieves 68% RPS compliance by 2038 under the base case load forecast (60% under high load and 77% under low load growth).

The renewable portfolio standard targets of 15% by 2021, 20% by 2022 and 40% by 2055 are all met in Scenario 4 under all load cases and strategies. The levels of renewable penetration exceed a linear trend towards the 60% renewable target by 2040, with the plan meeting or exceeding the target by 2038 in all load cases.

Exhibit 8-20: Renewable Portfolio Standards



CO_2 emissions for PREPA's fleet fall in the first ten years of the forecast driven by the retirement of the older fuel oil, diesel and gas units along with increased penetration of solar generation. Emissions fall 42% by 2027 and 61% by 2028 with AES coal retirement. Emissions continue falling after 2028 reaching an 86% reduction by 2038. The emission rate for the fleet falls from 1,336 lbs./MWh in 2019 to 368 lbs./MWh in 2038. As expected, the most efficient units, the new CCGTs have the lowest emission rates at 820 lbs./MWh. San Juan units converted to natural gas also show lower emissions rates at around 850 lbs./MWh as well as EcoEléctrica prior to retirement. The unit with the highest CO_2 emission rates is AES coal at 2,081 lbs./MWh prior to retirement in 2027.

Exhibit 8-21: CO2 Emissions PREPA System

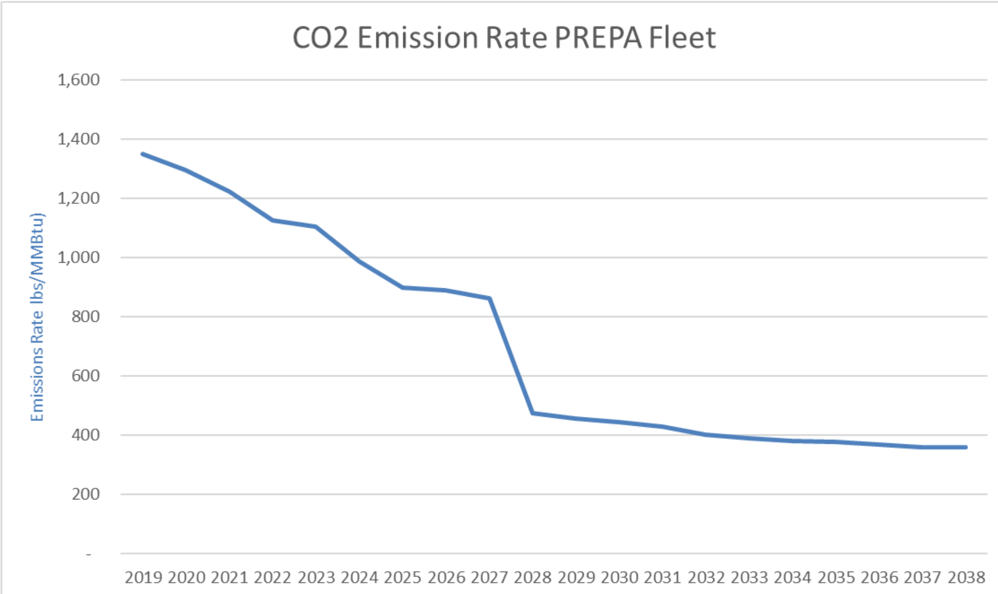


Exhibit 8-22: CO2 Emissions by Unit Type

lb/MWh	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
AES	2,174	2,166	2,145	2,150	2,115	2,097	2,082	2,108	2,081	-
EcoElectrica	906	835	856	803	-	-	-	-	-	-
Costa Sur 5&6	1,180	552	-	-	-	-	-	-	-	-
Existing Fleet (HFO)	1,396	3,003	1,421	1,550	1,842	3,620	-	-	-	-
Diesel CC (LFO)	170	-	1,001	90	3,818	2,084	1,384	-	-	-
Existing GTs (LFO)	1801	1768	1503	1771	1813	1695	1734	1777	1703	1668
SJ 5&6 With NG	864	858	855	851	850	850	852	852	852	853
New CCGT's	0	0	0	0	0	0	817	816	816	825
New Peaker gas	0	0	1198	1186	1178	1195	1193	1196	1199	1201
New Peaker diesel	0	0	0	0	0	0	0	0	0	1396
Total System	**1,336**	**1,322**	**1,285**	**1,204**	**1,057**	**942**	**1,028**	**1,027**	**998**	**708**

8.2.7 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan from $102.5/MWh in 2019 to $96.6/MWh by 2027 (real $2018), prior to AES Coal retirement, primarily due to the addition of solar and storage and the retirement of older generation. The costs increased in 2028, with AES retirement, and continue a gradual increase to reach $107.7/MWh by 2038 driven by new installations of battery storage. Customer rates are expected to decline through 2027 under this plan.

The net present value of all operating costs reaches $10.5 billion for 2019-2028 (nominal @ 9% rate). Over the study period, the NPV is $14.35 billion. Note that the 9% discount rate (6.86% on a real dollar basis), is the same discount rate used in the first IRP and it is based on the assumption that PREPA (or its successors) is able to resolve its current financial issues and can borrow the capital at this rate. It should not be confused with the WACC

which the weighted cost of capital for private parties that are assumed to invest in the resource additions.

Exhibit 8-23: Scenario 4 Production Costs

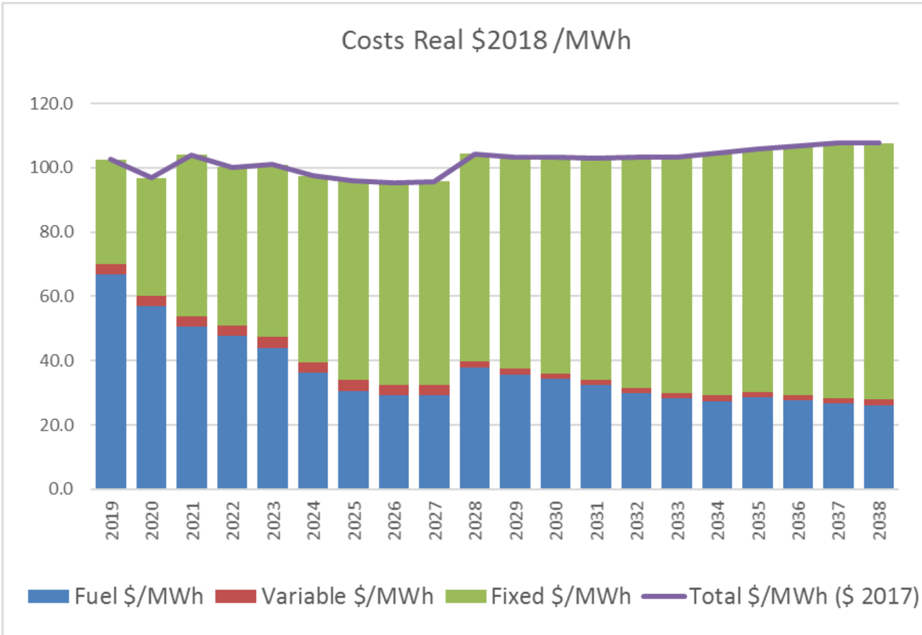


Exhibit 8-24: System Costs Base, High and Low Load

Case ID	Scenario	Strategy	Sensitivity	Load	AURORA LTCE	NPV @ 9% 2019-2038 k$	Average 2019-2028 2018$/MWh	NPV Deemed Energy Not Served k$ (1)	NPV + ENS k$	Capital Investment Costs ($ Millions)
S4S2B	4	2		Base	Yes	14,350,195	99.3	247,445	14,597,640	6,595
S4S2H	4	2		High	Yes	15,155,383	96.7	319,025	15,155,480	5,629
S4S2L	4	2		Low	Yes	12,865,937	96.5	198,037	12,866,033	5,321

* Total system costs include generation, fuel, EE and regasification costs

Under the high load case, the production costs are $6.50/MWh lower on average with an NPV of $15.2 billion, $800 million over the base case. This is driven by more fuel consumption with a higher load.

Under the low load case, the average system costs are $4.39/MWh lower compared to the base case with the overall NPV of the portfolio much lower at $12.8 billion. The reduction in costs is mostly driven by lower demand and fuel consumption, and the F-class CCGT at Palo Seco not developed.

8.2.8 Resiliency (MiniGrid Considerations)

A critical component of the formulation of the 2018 Integrated Resource Plan (IRP) is the identification of electrical islands or “MiniGrid” into which the system may be segregated after

a major atmospheric event (e.g. hurricane). In other words, the MiniGrids are regions of the system that are interconnected with the rest of the electric power system via lines that may take over a month to recover after a major event, and should be able to operate largely independently, with minimum disruption for the extended period of time that would take to recover full interconnection. In addition to the MiniGrids, there are also microgrids located within some of the MiniGrids that will be isolated from the MiniGrid after a major event. The methodology for the initial definition of the MiniGrids and Microgrids is described on Appendix 1.

The Siemens team evaluated the potential cost of energy not served in the case of a hurricane impacting the island and placing the system under a mini-grid operation for one month while the transmission network is repaired. This cost is NOT a forecast of future cost, but rather a high-level determination of how the different portfolios resulting from the combination of Scenarios and strategies would perform if every 5 years starting in 2022 a major hurricane impacted the island resulting in the operation of the MiniGrids for one month ("Deemed Energy Not Served"). The Deemed Energy Not Served was determined based on the total forecasted load at each MiniGrid, including critical, priority and balance, and the generation that would be available from thermal and renewable resources, complemented by storage. For the costs of energy not served we took into consideration that during grid isolated operation the load shedding will be on an announced and rotating basis and targeting loads where the impact would be the least (typically residential loads), with limited duration. The Siemens team used a value of $ 2,000/MWh for costs of energy not served, about half of the lower expected cost for Puerto Rico (see Exhibit 7-22) and in line with the costs seen in another jurisdiction (see Exhibit 7-16).

As shown in Exhibit 8-26, the net present value of the overall portfolio costs under the base case would increase by $247.5 million due to deemed energy not served. Under the high load case, the increase in portfolio costs is $319 million, and in the low load case $198 million.

In Scenario 4, the critical and priority loads for the MiniGrid regions of Carolina, Caguas, Cayey, Arecibo and Mayagüez South are not met with local generation while the plan is being developed in 2019 through 2022, as shown below for the Carolina MiniGrid. The total load in the MiniGrid would be covered by local generation (including PV and storage) after 2025 in Carolina (see Appendix 1 for more details on load generation balance and design of the MiniGrids).

Exhibit 8-25: Carolina Energy Coverage under a Minigrid Operation

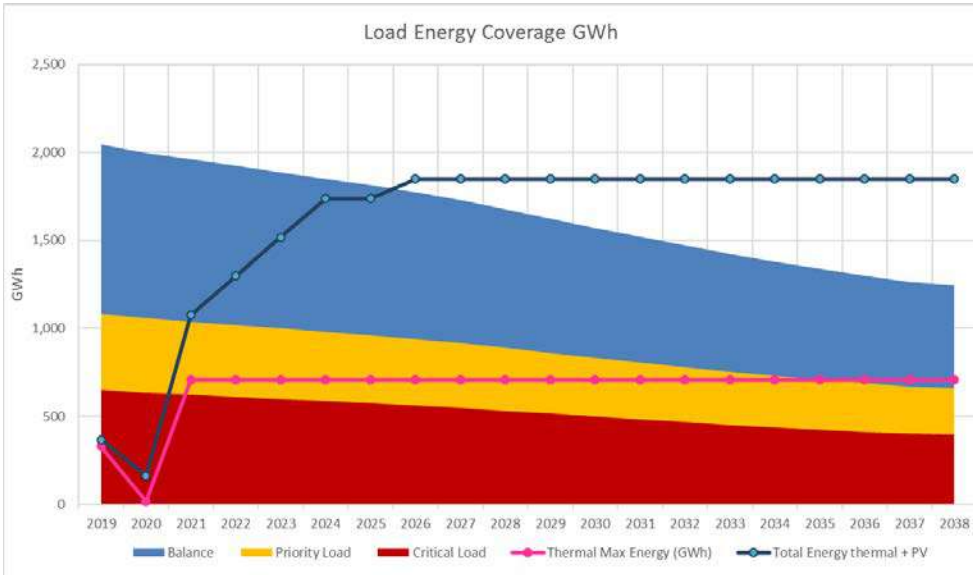


Exhibit 8-26 summarizes the present value of the cost of the “Deemed Energy Not Served” by MiniGrid region for Scenario 4 Strategy 2 and base load forecast.

Exhibit 8-26: Present Value of Cost of Deemed Energy Not Served by MiniGrids

MiniGrid	NPV Cost ($000)
San Juan-Bayamon	$ -
Ponce	$ -
Carolina	$ 73,980
Caguas	$ 87,124
Arecibo	$ 79,405
Mayaguez-North	$ -
Mayaguez-South	$ 143
Cayey	$ 6,792
Total	$ 247,445

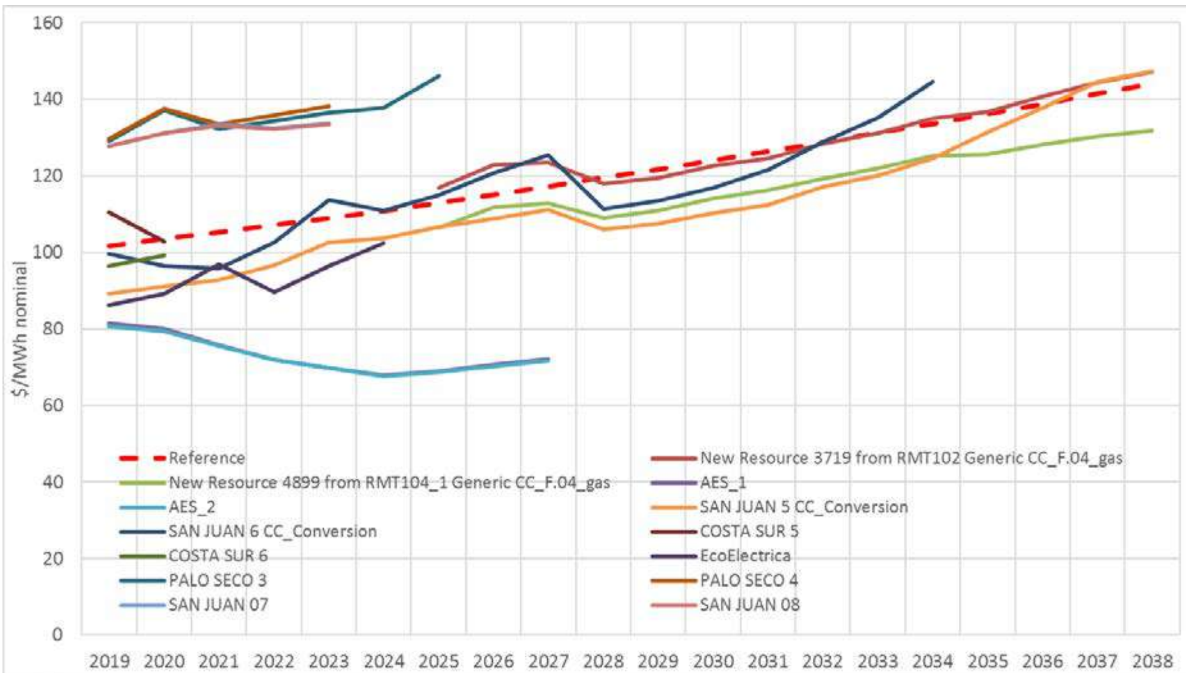
The largest potential costs are for Caguas and Carolina, followed by Arecibo and Cayey.

8.2.9 High Efficiency Requirement Fossil Generation

For demonstration of compliance with the High Efficiency Requirement, the levelized costs in $/MWh for new and existing CCGTs staying online meet the 100$/MWh requirement escalated at the inflation rate (i.e. in nominal terms), as shown in Exhibit 8-23. The new CCGTs stay below the $100/MWh requirement through the study period. San Juan conversions 5 & 6 stay below the requirement for most of the study period, in particular San

Juan 6, which has a better heat rate. San Juan 5 exceeds the requirements prior to its retirement and in some years when capacity factors drop below 50%. Also, in reference to the April 26th Order, PREPA is confirming that at least 60% of the total energy from fossil generation comes from highly efficient units by the end of the study period.

Exhibit 8-27: All in Cost of Generation under Scenario 4, Strategy 2



8.2.10 Considerations under Strategy 3

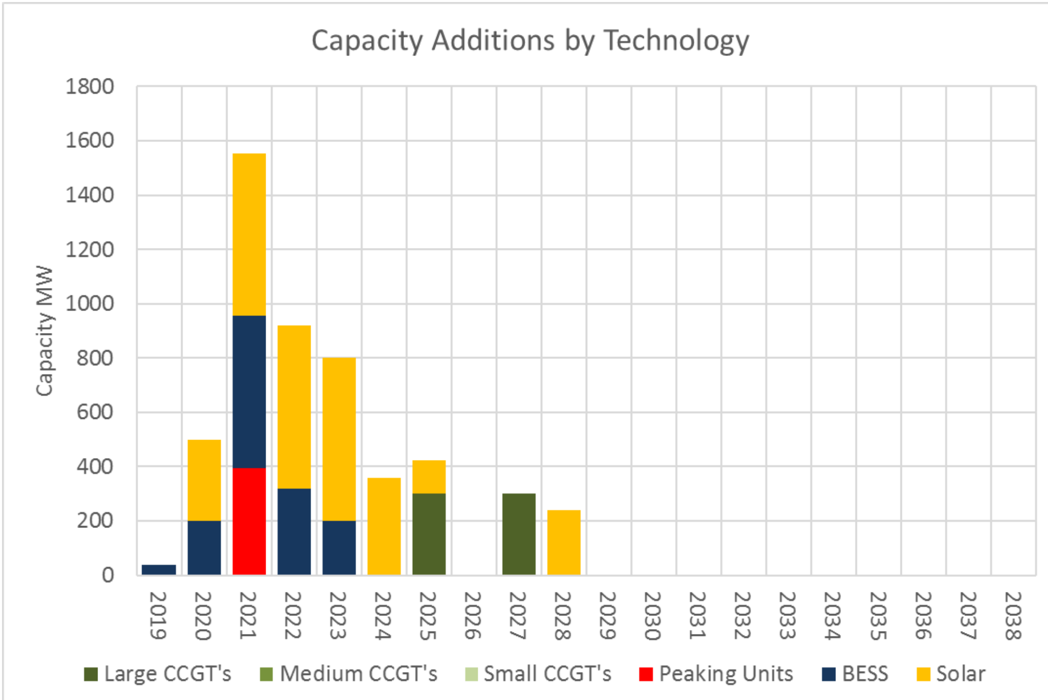
Under strategy 3, at least 50% of the peak demand needs to be supplied with local generation. Under this strategy, the economic simulation yields a very similar expansion plan to Strategy 2. However, this strategy provides less flexibility and resiliency at the mini-grid level and for this reason has higher potential costs from energy not served, in case of a major disruptive hurricane.

Under Strategy 3 and Base load forecast, the expansion plan is similar with 2,820 MW of solar PV built over the study period. Under the Strategy 3, the simulation has a faster build out of solar through 2025 with 2,580 MW compared to 2,220 under Strategy 2 (see Exhibit 8-8).

There is 1,320 MW of battery storage built in 2019-2022 (in line with Strategy 2). In the long-term, there is an incremental 320 MW of battery storage built under Strategy 2, after an expert review to reduce curtailments and system costs. Two F-class CCGTs at Palo Seco and Costa Sur are built with the CCGT at Palo Seco built in 2027 instead of 2025 as in Strategy 2. In addition, 394 MW of peakers are built in 2019-2025 (23 MW higher than Strategy 2).

The high and low load cases were not simulated under Strategy 3, per PREB's direction after finding Strategy 2 to have lower system costs.

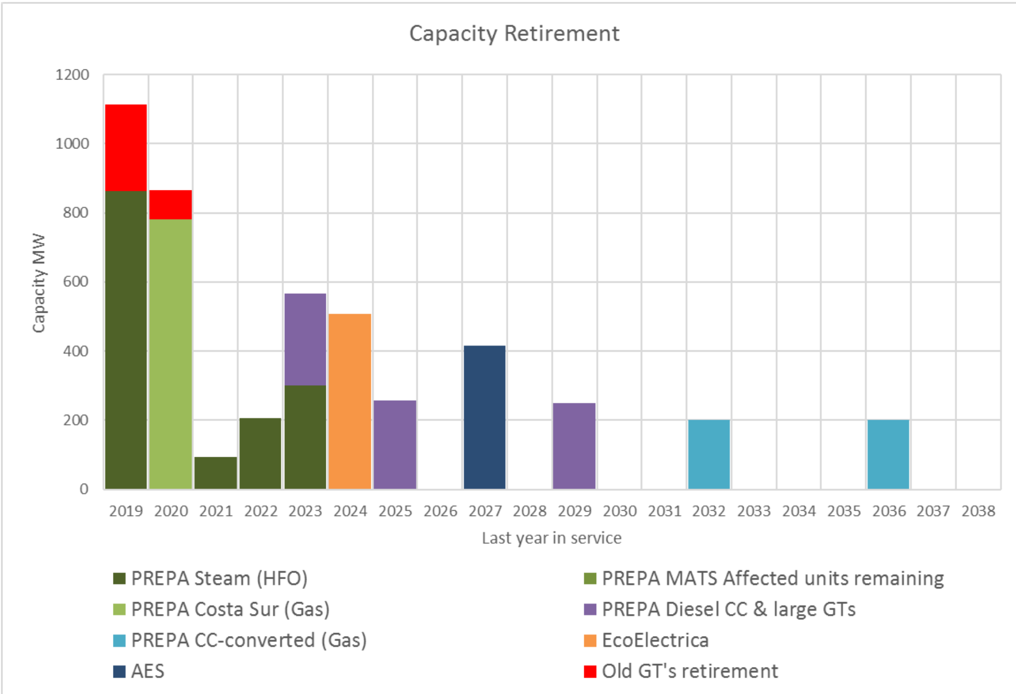
Exhibit 8-28: Capacity Additions Scenario 4, Strategy 3



Retirements follow the same schedule of units retired as strategy 2, with the economic retirement of Aguirre ST 1 and 2 at the end of 2019, Palo Seco ST 3 and ST4 by the end of 2022 and 2023, respectively. San Juan units ST 7 & 8 are retired by the end of 2021 & 2023, respectively).

EcoEléctrica is economically retired by the end of 2024. Likewise, this retirement is triggered by the entry of a new CCGT at Costa Sur (F-Class) and happens irrespective of the load forecast. Costa Sur 5 & 6 last year in service is 2020.

Exhibit 8-29: Capacity Retirements Scenario 4, Strategy 3 (last year in service)



Under this strategy, renewable penetration is lower at 54% by 2038. Overall emissions decline over 82% by 2038, slightly below Strategy 2.

The overall portfolio costs are slightly higher under Strategy 3 at $14.4 billion, 66 million higher than Strategy 2.

Including the potential costs of energy not served under mini-grid operations, the overall costs of the portfolio is $14.7 billion, at present value, also higher that Strategy 2 $14.6 billion.

Exhibit 8-30: Comparison Portfolio Costs Scenario 4, Strategy 2 and 3 for Base Load

Case ID	Scenario	Strategy	Sensitivity	Load	AURORA LTCE	NPV @ 9% 2019-2038 k$	Average 2019-2028 2018$/MWh	NPV Deemed Energy Not Served k$ (1)	NPV + ENS k$	Capital Investment Costs ($ Millions)
S4S2B	4	2		Base	Yes	14,350,195	99.3	247,445	14,597,640	6,595
S4S3B	4	3		Base	Yes	14,416,274	99.9	279,349	14,695,623	6,188
S4S1B	4	1		Base	Yes	14,278,224	99.3	876,448	15,154,671	6,212

At the regional MiniGrid level, the MiniGrids with the highest risk and potential costs of having load not served during a disruptive hurricane are Carolina, Caguas and Mayaguez South. As a result, the present value cost of deemed energy not served is $279 million, $31 million higher than Strategy 2.

Strategy 2 provides a lower cost plan with higher resiliency and reliability.

8.2.11 Considerations under Strategy 1

Strategy 1 is a centralized plan with no minimum generation requirements at the MiniGrid level. The Strategy produces an expansion plan that is less expensive than strategy 2, which is Siemens' recommended strategy. A centralized plan has a greater risk and potential costs for unserved energy after a disruptive hurricane. The expansion plan is very similar to strategies 2 and 3 (see Exhibit 8-8 S4S1B).

The expansion plan is similar with 2,700 MW of solar PV built during the study period, only 120 MW lower than strategy 2. The plan builds solar PV at a faster pace with 2,700 MW through 2025 compared to 2,220 under Strategy 2 and 2,580 MW under Strategy 3.

There is 1,240 MW of battery storage build in 2019-2022 (similar to Strategy 2). In the long-term, there is an additional 400 MW of battery storage build under this strategy, with a total of 1,640 MW, in line with Strategy 2. Neither the F-Class CCGTs at Palo Seco nor the CCGT in Costa Sur are built but instead selects an F-class in Yabucoa in 2025 and an F-Class at Mayagüez in 2028, which is a less resilient solution in particular with respect of the Mayaguez CCGT that would be poorly located to replace the Palo Seco CCGT. However, this highlights that from an integrated system point of view there is some equivalence of these sites.

371 MW of peakers are built in 2019-2025, in line with Strategy 2.

Retirements follow the same schedule of units retired as strategy 2, with the economic retirement of Aguirre ST 1 and 2 after 2019 & 2020, Palo Seco ST 3 and ST4 after of 2019 (much earlier than the other two Strategies). San Juan units 7 and 8 units are retired by the after 2019, earlier than the other two Strategies as well. As indicated earlier these dates are references and would only actually occur when the new supply is in place and the load achieves the forecasted levels.

EcoEléctrica is economically retired by the end of 2024, in line with Strategy 2. Costa Sur 5 & 6 last year in service is 2022 and 2020 as it could not compete with EcoEléctrica. Both of the San Juan unit conversions are retired in the 2030s.

Exhibit 8-31: Capacity Additions Scenario 4, Strategy 1

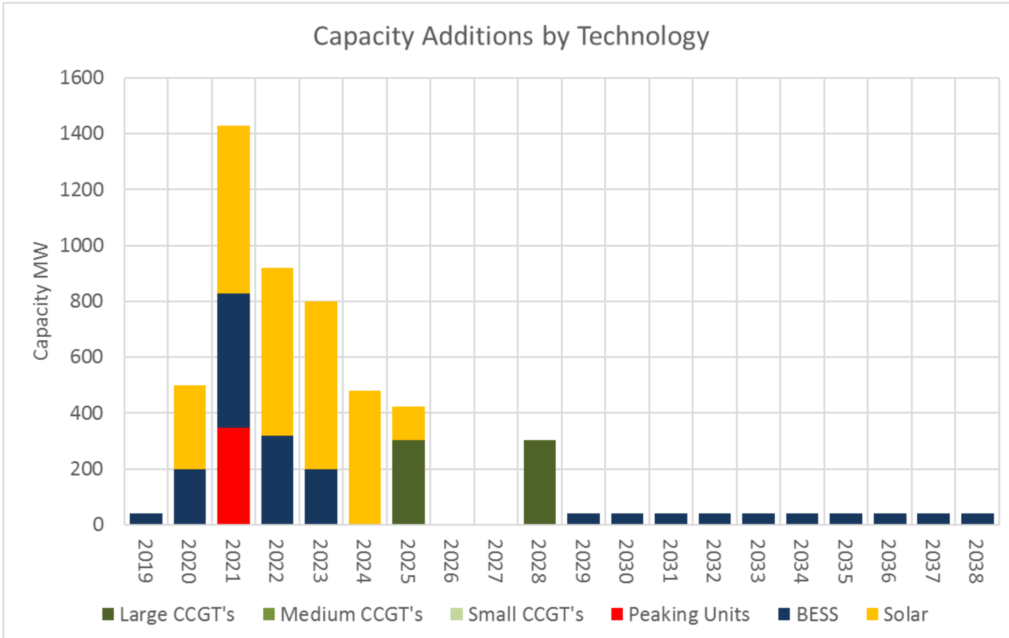
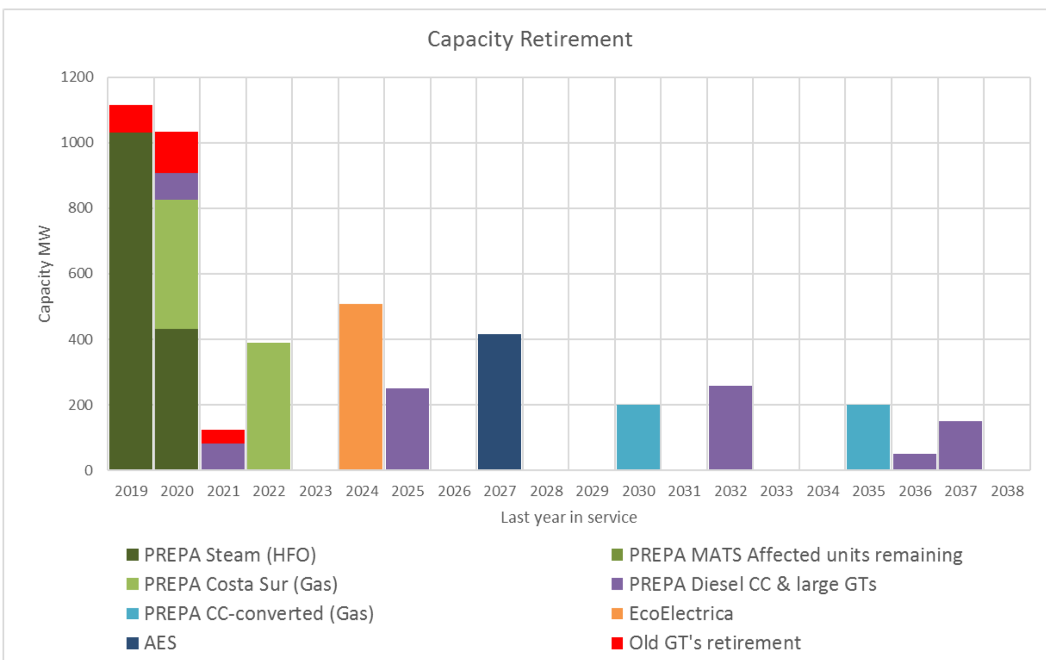


Exhibit 8-32: Capacity Retirements Scenario 4, Strategy 1



The overall portfolio costs are lower under this strategy driven by lower fuel and fixed costs. However, the potential costs from Deemed Energy Not Served under a mini grid operation in the event of a major hurricane is much higher under Strategy 1 at $1,109 million compared to $247.4 million under strategy 2, which is expected given the location of the resources under this strategy,

The potential for unserved energy arises in most MiniGrid regions. The regions with highest potential costs from unserved energy under MiniGrid operations are San Juan-Bayamon, Carolina, Caguas and Arecibo.

Exhibit 8-33: Comparison Portfolio Costs Scenario 4 Strategy 2, 3 and 1

Case ID	Scenario	Strategy	Sensitivity	Load	AURORA LTCE	NPV @ 9% 2019-2038 k$	Average 2019-2028 2018$/MWh	NPV Deemed Energy Not Served k$ (1)	NPV + ENS k$	Capital Investment Costs ($ Millions)
S4S2B	4	2		Base	Yes	14,350,195	99.3	247,445	14,597,640	6,595
S4S3B	4	3		Base	Yes	14,416,274	99.9	279,349	14,695,623	6,188
S4S1B	4	1		Base	Yes	14,278,224	99.3	876,448	15,154,671	6,212

Under this strategy, the renewable portfolio standards are met with a 68% renewable generation by 2038.

8.2.12 Sensitivities Considerations

The Siemens team evaluated 4 sensitivities under Scenario 4 to isolate the impacts of certain important variables while holding other assumptions constant. For the 2018 IRP, four sensitivities were modeled.

Sensitivity 9: No Economic retirement of EcoEléctrica

As presented earlier, under S4S2B EcoEléctrica was displaced by the new CCGT at Costa Sur despite the 53% reduction in the fixed payments from 2022 onwards. Thus a sensitivity was ran forcing EcoEléctrica to stay online and the increase in the NPV of the total generation costs was used to estimate what would be the necessary additional reduction in fixed cost to make them the same.

As can be observed below the 53% reduction modeled was fairly close and with EcoEléctrica online instead of the CCGT the increase in the NPV is less than 1%

Exhibit 8-34: Comparison of cost with EcoEléctrica dropped (S2S4B) and EcoEléctrica forced to continue (S4S2S9B)

Case ID	Scenario	Strategy	Sensitivity	Load	NPV @ 9% 2019-2038 k$	Average 2019-2028 2018$/MWh	RPS 2038	NPV Deemed Energy Not Served k$ (1)
S4S2B	4	2		Base	14,350,195	99.3	68%	247,445
S4S2S9B	4	2	9	Base	14,480,364	99.6	68%	267,841
			Increase:		0.9%	0.2%		

The difference between the two NPVs is $ 130.2 million thus the NPV of EcoEléctrica fixed needs to be lower by this amount from the value modeled and as shown in the exhibit below

this would happen with a reduction of 60% instead of 53%. See S4S2S9B_Metrics)(Eco staying online)_SII.xlsx work paper for details on the below.

Exhibit 8-35: Determination of required reduction on Fixed Payments of EcoEléctrica

	Original	As Modeled		Modified	40%
Year	**Total Fixed Costs (Nominal**	**Fixed_Cost $000**	Reductio n	Reduction	New Fixed Costs
2019	194,517	194,519.23	0%	0%	194,516.60
2020	208,720	208,704.23	0%	0%	208,704.23
2021	240,149	240,148.52	0%	0%	240,148.52
2022	245,327	115,315.70	53%	60%	98,043.66
2023	250,662	117,800.73	53%	60%	100,175.71
2024	256,813	120,694.83	53%	60%	102,633.61
2025	261,615	122982.266	53%	60%	104,552.86
2026	267,288	125625.906	53%	60%	106,820.14
2027	273,078	128375.3	53%	60%	109,133.91
2028	279,748	131483.938	53%	60%	111,799.63
2029	285,059	133979.813	53%	60%	113,922.04
2030	291,255	136887.828	53%	60%	116,398.52
2031	297,523	139848.7	53%	60%	118,903.52
2032	304,849	143253.859	53%	60%	121,831.19
2033	310,583	145981.953	53%	60%	124,122.71
2034	317,330	149127.891	53%	60%	126,818.93
2035	324,206	152379.578	53%	60%	129,566.93
2036	332,169	156110.656	53%	60%	132,749.48
2037	338,452	159041.547	53%	60%	135,260.50
2038	338,452	159041.547	53%	60%	135,260.50
	NPV	$1,409,078.35		**NPV**	$1,278,909.35
	Target	$130,169.05		**Delta**	$130,169.00

Sensitivity 4: Ship-based LNG at San Juan is assumed to achieve permitting approval, but not the land based. The ship-based LNG at San Juan can basically supply the conversion of San Juan 5 and 6 and provide limited gas to other developments. It has reduced capacity in comparison to the land-based LNG option.

Under Sensitivity 4, only one new CCGT is installed in Costa Sur in 2020 . Solar installations are higher with 3,060 MW compared to 2,820 MW in the Base load case. Storage installations are the same with 1,640 MW (see Exhibit 8-8 S4S2S4B).

The Aguirre CC2 stays online through 2033, as well the San Juan unit 5 conversion. San Juan 6 retires in 2034 as in the base case.

Overall portfolio costs are about 116 million higher under this sensitivity, driven by higher fuel costs (some diesel partially offset by lower fixed costs with one less new CCGT compared to the base case). This case also has higher potential costs from unserved energy during a hurricane event.

Sensitivity 5: High gas prices.

Following PREB's order from April 2019, PREPA evaluated Sensitivity 5 without changes in the expansion plan compared to the base case. As a result, the primary impact is on fuel costs and overall portfolio costs. Thus, the NPV of costs are 905 million higher at $15.2 billion compared to the base case (see Exhibit 8-27). The risk to the portfolio from higher gas prices from LNG imports is significant. However, with the exception of Scenario 1. This increase affects similarly all cases.

Sensitivity 6: High cost of renewables

Following PREB's order from April 2019, PREPA evaluated Sensitivity 6 without changes in the expansion plan compared to the base case. As a result, the primary impact is on fixed costs and overall portfolio costs. Thus, the NPV of costs are 1,214 million higher at $15.6 billion. The risk to the portfolio from higher capital costs from renewables is significant. Solar installations would not change materially through 2025 in order to meet the 40% RPS target, however, in the long-term higher costs of renewables could impact economic additions to the system. Nevertheless, under an open competitive tender the Siemens team considers possible that PPAs for new solar would be bid at lower costs than the reference case. As is the case of higher fuel prices these increases would affect largely the same all Scenarios with the exception of Scenario 3 that assumes low costs and if the cost were to go to the high value it would have a major impact.

Exhibit 8-36: Comparison Portfolio Costs Scenario 4 Sensitivities

Case ID	Scenario	Strategy	Sensitivity	Load	AURORA LTCE	NPV @ 9% 2019-2038 k$	Average 2019-2028 2018$/MWh	NPV Deemed Energy Not Served k$ (1)	NPV + ENS k$	Capital Investment Costs ($ Millions)
S4S2B	4	2		Base	Yes	14,350,195	99.3	247,445	14,597,640	6,595
S4S2S9B	4	2	9	Base	No	14,480,364	99.6	267,841	14,748,205	6,265
S4S2S1B	4	2	1	Base	No	14,012,096	97.4	247,445	14,259,541	5,961
S4S2S4B	4	2	4	Base	Yes	14,466,325	100.9	345,809	14,812,134	6,552
S4S2S5B	4	2	5	Base	No	15,255,494	104.8	247,445	15,502,939	6,595
S4S2S6B	4	2	6	Base	No	15,565,108	106.7	247,445	15,812,553	8,756

* System costs includes generation costs, EE programs, fuel and regasification costs

8.2.13 Rate Impact

In the sections above, we presented the composition of least cost portfolio formulated under Scenario 4. In this section we estimate the potential impact of the S4S2B portfolio on the final rates to customers and compare the resulting final rates with the possible costs that the customers would incur for self-supply as described in Appendix 4 Demand-Side Resources and that basically include:

a) Residential Solar Photo-Voltaic (PV), use of net-metering
b) Grid-Defection; PV plus storage at levels that allowing become an autonomous self-supplier.
c) Combined Heat and Power (CHP)
d) Diesel Generator

8.2.13.1 Rate Components

We provide below a high-level description of the individual components that make up the final rates resulting from the S4S2 generation portfolio.

The final customer rate can be broken down into at the following basic components:

a) Generation cost of energy delivered to the customers (generation)
b) Non-generation utility component (transmission & distribution + administrative)

The generation rate component is directly dependent upon the Capital, Fixed Operating and Maintenance (FO&M), Regasification, Fuel, and Variable Operating and Maintenance (VO&M) costs incurred in building and operating the generation portfolio. This component is portfolio specific and will change as the generation asset mix changes. Also, this rate reflects the total generation needed to serve the customer load accounting for the technical and non-technical losses in the transmission and distribution network and PREPA's internal self-consumption. The Portfolio includes a certain amount of customer self-supply and the total generation is reduced by this self-supply for the purposes of calculating the costs.

The non-generation utility component is PREPA's Non-Fuel and Power Purchase (non-F&PP) rate. This component reflects the transmission and distribution costs and administrative and is held constant across generation portfolios and was provided by PREPA's advisors for this analysis; it has an average value of nominal 14.2 cents per kWh for the next 10 years and considers the reduction in load and energy efficiency effects.

The final resulting rate for the case is computed as the sum of the individual components described above and is then compared with the cost of customer-based alternatives.

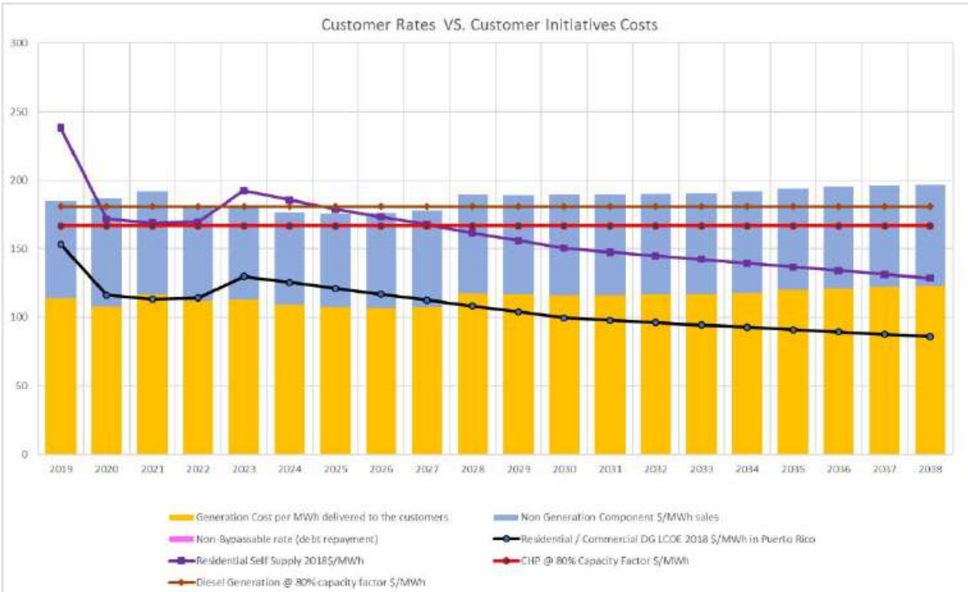
8.2.13.2 Results of Comparison to Customer Based Alternatives

In this section we describe the results of the analysis we performed comparing the final S4S2 rates to unit costs for customer-based alternatives.

From the results, which are illustrated in Exhibit 8-30, we have the following observations and inferences:

- The unit costs for all the customer alternatives considered are lower than the final all-in S4S2 generation portfolio rate.
- The levelized cost of customer owned generation is higher than the cost of the utility generation delivered to the customer (that includes the effect of loses), until 2028 (when AES Coal retires). However, this cost of customer owned generation is significantly lower than the total rate and confirms the assumption in the DG forecast that the continuance of 'net-metering' rates will foment customer side roof top PV concurrent with the high adoption rates observed to date.
- These results also indicate that with the expected reduction in renewable generation costs, customers may be motivated to self-supply if they are able to raise the capital investment required for installing the self-supply option or if a developer installs the equipment and recovers the investment through leases or other financing options.

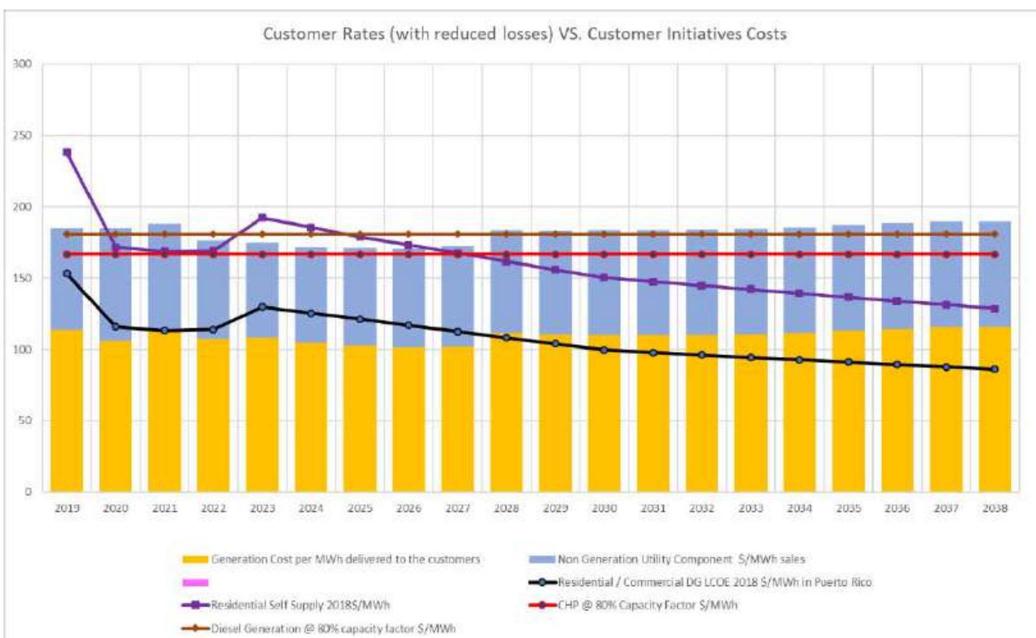
Exhibit 8-37:Final S4S2 Generation Portfolio Rates Compared to Unit Costs of Customer Alternatives



See workpaper: S4S2B_Rate_Impact_V3.xlsm

We analyzed another case where we reduced the non-technical losses to typical values observed in the US (0.5% or less). The resulting final rate for the S4S2 generation portfolio, also reduces, but not to the extent that our observations and inferences discussed above change. This updated comparison chart is given in the exhibit below.

Exhibit8-38: Final S4S2 Generation Portfolio Rates Assuming Reduced Losses



See workpaper: S4S2B_Rate_Impact_V3.xlsm

8.2.14 Nodal Analysis Scenario 4, Strategy 2

The Siemens team evaluated the least cost plan under Scenario 4 using a nodal simulation. The objective is to identify the effects of transmission on the key metrics of congestion, technical losses, production costs, renewable curtailment and energy not served.

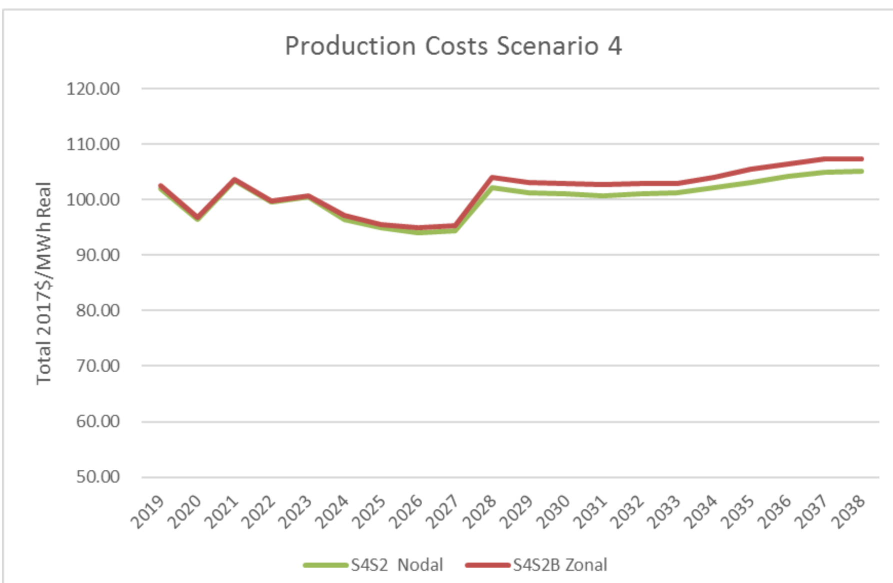
The results of the nodal runs show that in the first 10 years (2019 – 2028) the production costs of the nodal runs match very closely with those of the zonal runs used for the LTCE assessment (see Exhibit 8-32). The transmission technical losses, that were not considered in the zonal runs, but are assessed in the nodal are fairly low starting from about 1.1% and dropping to 0.4% by the end of the period as consequence of the reduced load and greater distribution of the generation, as shown in Exhibit 8-33.

The amount of curtailment observed for the new solar generation was lower in the Nodal runs as shown in Exhibit 8-32, which confirms that transmission is not expected to create curtailment.

There was no energy not served in the nodal runs, which is in line with the results of the zonal runs.

In summary the minimal impact of transmission was expected due to the greater distribution of generation resources and reduced load.

Exhibit 8-39: Production Costs Nodal vs. Zonal and Renewable Curtailment



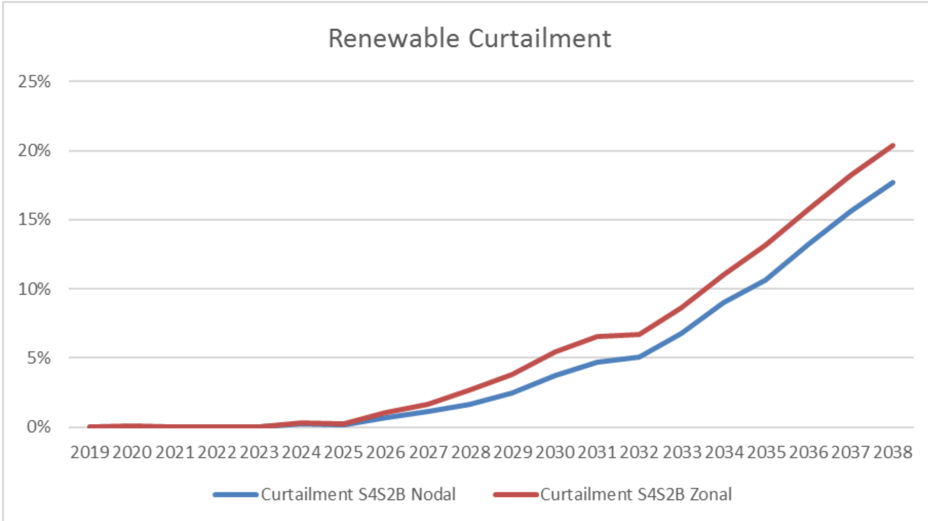


Exhibit 8-40: Transmission Losses Differences

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Losses Nodal	1.1%	1.0%	0.7%	0.6%	0.6%	0.6%	0.5%	0.6%	0.5%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Losses Zonal	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

8.3 The ESM Plan

The Energy System Modernization Plan (ESM) is a derivative of Scenario 4 based on fixed generation expansion additions discussed below and detailed in the work paper "Considerations on the ESM Plan". As described in the workpaper, the purpose of the ESM Plan is to expedite the implementation of a preferred plan utilizing procurement options as described in the workpaper that have the highest probability of achieving the goals of improving reliability and reducing costs for the ratepayers. The ESM also preserves optionality, through early development and permitting efforts, for alternative resource locations. The ESM contains implementation options consistent with the broad framework of the IRP scenarios designed to support generation diversity, grid resiliency, and cost efficiency and that had the best chance of success.

The ESM's long term capacity expansion plan (LTCE) was developed taking into consideration some pre-defined decisions as described below, other decisions as is the case of new Photovoltaic or wind generation, storage, other thermal and the retirement of existing generation were selected by the LTCE.

Siemens compared the ESM plan to the applicable least cost plan (Scenario 4, strategy 2) under base load forecast.

The ESM is based on the following fixed decisions:

- Replace all 18 existing Frame 5 GT's at optimized locations with new mobile units GTs (23 MW each) or equivalent, as a fixed decision to come online by 2021 and with containerized LNG as a fuel option (418 MW total).
- Develop an LNG terminal at Yabucoa (Caguas) and a 302 MW F-Class CCGT in June 2025 to be built as a fixed decision.
- Develop an F-Class CCGT at Palo Seco by 2025 fueled by a land-based LNG at San Juan
- Develop new ship-based LNG at Mayagüez and conversion to dual fuel of the Aero Mayagüez units (4x50MW) as a fixed decision. In addition, as an option, the case includes the possibility of building a 302 MW F-Class CCGT at Mayagüez. The last option was not selected by the LTCE.

The following assumptions were also included in the simulation of this Scenario:

- Load Forecast is treated via a Base, High and Low case.
- EcoEléctrica is assumed to stay in service but with the fixed payment reduced by 53% from 2022 onwards (see section 4.2.1.5.). This reduction was determined using the results of the initial runs for the ESM and selecting it so that the NPV of EcoEléctrica's all in costs was the same as that of an equivalent reference CCGT that could produce the same capacity and energy. This analysis is documented in the workpaper: EcoElectrica_NPV_ASSESSMENT_Initial.xlsx.
- EcoEléctrica as has been traditionally modeled as a Base Load plant and it was allowed only to cycle on a weekly basis. However, this limitation in a system with high penetration of renewable generation, as in the future Puerto Rico system, would

create important renewable generation curtailment and/or increase the need for investments in storage. Hence the assumption was made that for EcoEléctrica to remain competitive and viable in this future system it would have to be modified so it could be turned off during daytime (e.g. after 6:00 to 7:00 am) and turned back on in the evening (after 4:00 to 5:00 pm) to supply the night load. Note that to achieve this EcoEléctrica would need to keep its HRSG a warm / hot conditions and possibly improve its controls and equipment to manage the thermal stresses. EcoEléctrica was modeled with a minimum down time of 2 hours and a minimum up time of 2 hours, instead of the initially modeled 5 days minimum up time.

- San Juan Units 5 & 6 are converted to gas in June 2019. The cost of the conversion is assumed to be structured as a capacity payment of $5 million on an annual basis per unit ending on 06/30/2024.
- AES is assumed to expire in 2027 and not renewed in line with Act 17-2019 regulations
- San Juan units are subjected to fuel constraints of delivery to San Juan (ship-based fuel constraints for July 2019-June 2024, and land-based LNG constraints from July 2024 through the end of the forecast period.
- Energy Efficiency programs are assumed to meet the requirement of Act 17-2019, i.e., 2% per year of incremental savings attributable to new energy efficiency programs through 2037, resulting in 36% cumulative energy savings by 2038. As a result, the load under the base case is 50% below 2019 levels by 2038, when in addition to the EE the effects of customer owned generation are accounted for. Comparing to the February filing, the load is now 20% lower by 2038.
- The Scenario assumes solar and storage costs and availability based on reference case assumptions. New PV installations are limited to 300 MW in 2020 and 600 MW annually thereafter. Storage installations are limited to 40 MW in 2019, 200 MW in 2020 and 600 MW annually thereafter.
- The plan reflects Act 17-2019 with RPS targets of 20% by 2022, 40% by 2025 and 60% renewable penetration by 2040. The new RPS targets are twice as high compared to the previous legislation by 2025, when most solar generation needs to be built. The plan achieved a renewable penetration above the targets starting in the late 2020s with more aggressive reduction in load starting in those years as a result of the cumulative impact from Energy Efficiency savings.
- Improved capacity factors for Wind based on NREL ATB TRG-8, mid case and add this as an option to the LTCE selection and offered as a resource to the Aurora LTCE calculations. New wind turbine generation was not selected under the “mid” case renewable price projections, despite the fact that these resources do have some contribution to the nigh peak (about 20%).
- Any non-renewable generator is modeled as fully depreciated by 2050 and ready for retirement by then, in line with the requirement of 100% renewable generation by that year.
- High Efficiency Requirement Fossil Generation - For demonstration of compliance, PREPA check compliance using two requirements:

– The real levelized costs in $/MWh for new and existing CCGTs staying online meet the 100$/MWh requirement in real 2018 dollars. As indicated, it is generally the expectation that when new or existing CCGTs (namely EcoEléctrica and San Juan 5 & 6 gas conversions) dispatching at capacity factors higher than 60%, the levelized costs of energy is at or below $100/MWh.

- Land based LNG Cost at San Juan sized to the new CCGT F class built in the North at Palo Seco (Bayamon). Siemens evaluated the potential maximum fuel used at the terminal from the new combined cycle plus the San Juan 5&6 conversions to gas. As such, the CapEx required is slightly lower compared to previous simulations. Exhibit 8-6 shows the new capital costs assumptions for all terminals. Exhibit 8-7 illustrates the potential maximum volume at the terminal based on the maximum generation from the new F Class unit and the San Juan conversions. The LPG option is not considered in the total, as is optional in the simulation.

Exhibit 8-41: Capital Costs Assumptions LNG Terminals

Infrastructure Option	CAPEX $MM (2018$)	Annual OPEX $MM (2018$)	Max Daily Gas Volume (MMcf/d)	Max Gas Volume (MMBtu/month)	Max Capacity MW	CAPEX $/kW (2018$)	Annual OPEX $/kW (2018$)	CAPEX + Annual OPEX $/kW (2018$)
Land-based LNG at San Juan Port (w/o pipeline)	$ 471.62	$ 24.52	125.9	3,924,711	702	68	35	103
Ship-based LNG at Mayaguez (west)	$ 185.00	$ 9.62	53.4	1,642,116	302	62	32	94
Ship-based LNG at Yabucoa (east)	$ 185.00	$ 9.62	53.4	1,642,116	302	62	32	94
Ship-based LNG (FSRU) at San Juan Port (supply to San Juan only)	$ 185.00	$ 9.62	50.4	1,549,815	350	54	27	81

Exhibit 8-42: Maximum Fuel Usage

	San Juan 5 Peak Fuel Consumption	San Juan 6 Peak Fuel Consumption	F-Class Consumption	Total
Capacity	200	200	302	702
Capacity Factor (used to determine peak consumption)	100%	100%	100%	100%
Heat Rate BTU/kWh	7625	7853	7552	
Fuel MMCf/day	35.7	36.8	53.4	125.9
Max Gas Volume (MMBtu/month)	1,113,250	1,146,538	1,664,923	3,924,711

- PREPA can buy RECs to meet the RPS requirements from DG. Current models assume that compliance 100% is achieved with utility scale solar only, as no reference price for the REC's is available.

Exhibit 8-43. ESM Summary of results

Case ID	Sensitivity	Load	AURORA LTCE	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peker Conversion	Other	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)	Customer Owned Generation 2038 (MW)
ESM		Base	Yes	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2580	1640	1176
ESM High		High	Yes	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,340	1040	2460	1040	1176
ESM Low		Low	Yes	✔	EcoEléctrica Instead	✔	✔	✔	–	421	1,920	1040	1980	1040	1176
ESMS1B	1	Base	No	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2580	1640	1176
ESMS6B	6	Base	No	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2580	1640	1176
ESMS5B	5	Base	No	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2580	1640	1176

8.3.1 Generating Additions

The economic simulation of the ESM case results in 2,580 MW of utility scale PV additions over the planning period, 300 MW below Scenario 4. Most of solar PV installations happen

through 2025. This is an increase of 186% over the ESM Plan filled on February 2019, which had a total of 900 MW of new solar, and 30% higher than the sensitivity where the ESM was set to reach 50% RPS by 2040 (1980 MW). All driven by the increase in RPS targets from 15% by 2027 to 40% by 2025 and 60% by 2040.

Under the high demand case, 2,460 MW of solar PV is installed over the study period,120 MW below the base load ESM case. In line with the base case, 1,320 MW of solar PV is installed in 2019-2022 and most of the solar PV is installed through 2025 in order to meet the 40% RPS target with 2,340 MW. In contrast, under the low demand case 1,980 MW of solar PV is installed (600 MW less than the base case), with the same amount installed through 2022.

If the capital costs for solar photovoltaic results to be higher or lower than forecast, the amount of solar installations would not materially change in order to meet the RPS Targets of 15% and 20% in 2021 and 2022, respectively. In all scenarios, nearly 1,400 MW of solar PV are needed to meet the RPS targets by 2022 and at least 2,220 MW by 2025. In the long-term the amount of solar installed may increase with lower capital costs or otherwise with higher capital costs. Under PREB order from April 2019, the Bureau asked PREPA to run scenarios around high and low renewable capital costs without changing the expansion plan in the base case under Strategy 2 [73]. The results are discussed in section 8.3.8 Sensitivity Considerations.

No wind turbine generation was built by the plan even though it was offered as an option in the model.

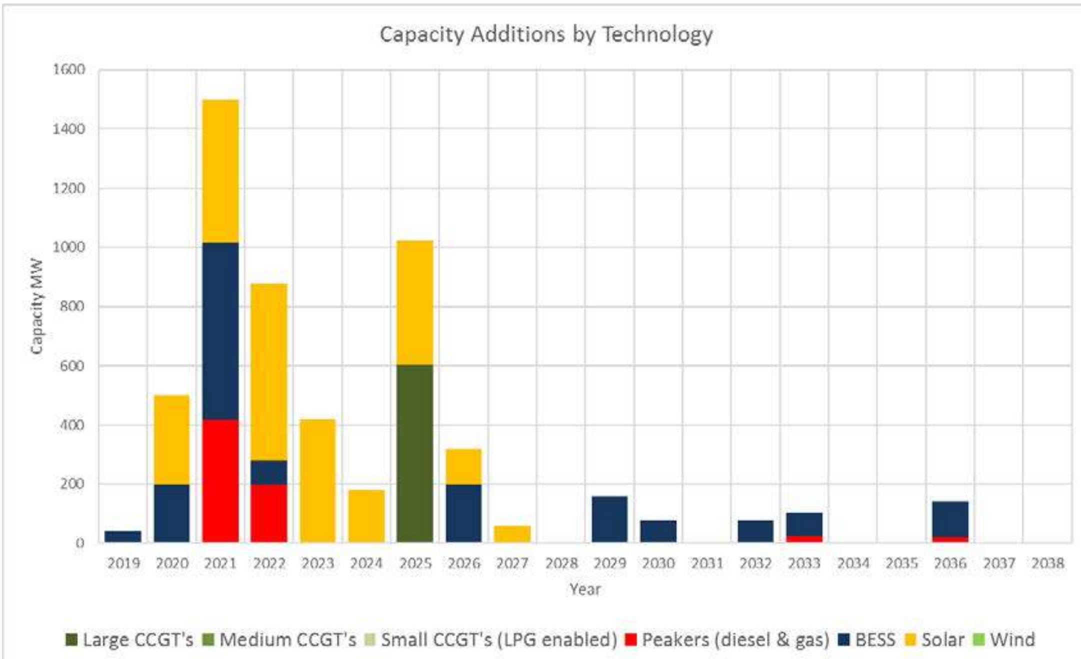
1,640 MW of battery energy storage is built over the planning period, with 900 MW installed through 2025. The amount of storage built over the study period is twice as much compared to the 800 MW reported in the February filling for the ESM base, all driven by a larger amount of solar installations in this scenario to meet the new RPS targets. In the high and low load cases, 1,040 MW of storage is built in both cases. A robust decision is to build a minimum of 800 to 1000 MW of storage by 2025, with the expected storage capital prices. The Siemens team performed a detailed simulation of the cases finding that an enhanced amount of storage was needed to support the renewables and reduced curtailments and system costs. The ratio of storage to solar is 64% under the base case load with a lower ratio needed in the high and low load cases at 53% and 42%, respectively.

The thermal additions are largely the ones identified as an input to the plan. The plan does not develop a new CCGT at Costa Sur, due to the assumed continued operation of EcoEléctrica. Thermal additions are the same as the base case under the high and low load cases, including the mobile gas-fired peaking capacity and Mayagüez conversion. In previous filing of the IRP, the high and low load cases resulted in some changes in the thermal expansion plan with a small CCGT built in Ponce or San Juan and some diesel peakers. In the new ESM plan, a total of 618 MW of gas peakers are installed in the plan by 2025 including the 418 MW mobile peakers and the 200 MW Mayaguez conversions to gas. In the 2030s two additional small peakers of 23 MW are installed in the plan to support mini-grid operations in the Ponce East and San Juan.

[73] The PREB asked PREPA to run scenarios based on the Strategy with lower NPV costs under base load. Strategy 2 was found to have lower system costs for Scenario 4.

A small 114 MW CCGT unit in the North was offered as an option but it is not selected by the model economically or any other gas unit besides the planned new CCGTs at Bayamon and Yabucoa (Caguas).

Exhibit 8-44: ESM Plan Capacity Additions



Capacity by Technology MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Large CCGT's	0	0	0	0	0	0	604	0	0	0
Medium CCGT's	0	0	0	0	0	0	0	0	0	0
Small CCGT's (LPG enabled)	0	0	0	0	0	0	0	0	0	0
Peakers (diesel & gas)	0	0	418	200	0	0	0	0	0	0
BESS	40	200	600	80	0	0	0	200	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Total Distchable Additions	**40**	**200**	**1018**	**280**	**0**	**0**	**604**	**200**	**0**	**0**
Solar	0	300	480	600	420	180	420	120	60	0
Total Additions	**40**	**500**	**1,498**	**880**	**420**	**180**	**1,024**	**320**	**60**	**0**

8.3.2 Capacity Retirements

The installation of the PV and Storage in 2020 allows for the economic retirement of Aguirre ST 1 and 2 (end of 2019), Palo Seco ST 3 & 4 after 2024 and San Juan ST 7 & 8 after 2021 and 2023. As mentioned before these retirements are selected by the model based on the assumption that new generation is in place and that the load has declined as projected.

EcoEléctrica is modelled to remain in service with an adjustment to the contract that was defined to be competitive with a CCGT. The fixed payments are reduced to about 57% of current values and the unit is assumed to be able to cycle as required to accommodate the renewable generation production variations. EcoEléctrica dispatches at 30-92% capacity factor range, depending on the year. The lowest dispatch capacity factors happen in the later part of the planning period, while the highest capacity factors happen early in the forecast.

Costa Sur 5 & 6 last year in service is 2020, retired with the fall in load and the entry of solar PV and Storage.

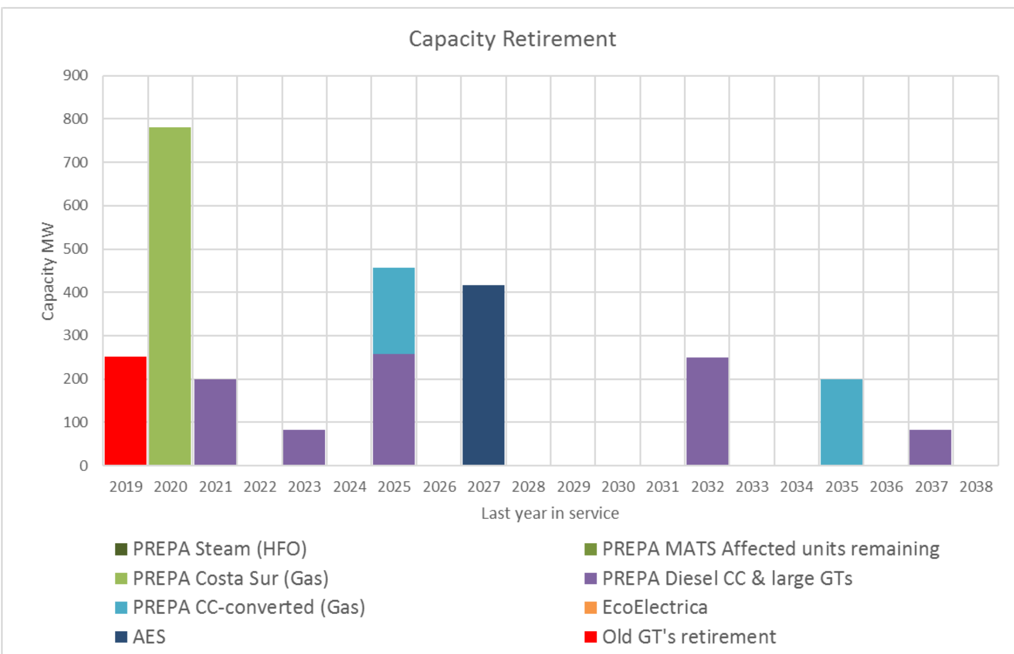
AES is retired at the end of 2027, not economically but by defined model input and in line with the existing regulation.

The Aguirre CCGT unit 1 is retired after 2025 and unit 2 later after 2032. Under the high demand case, Aguirre CCGT unit 2 is retired after 2025. Under the low demand case Aguirre CCGT unit 2 is retired after 2028.

The four units of Aero Mayagüez are converted to gas by 2022 and stay online through the planning period. The Cambalache units stay online for reserves and MiniGrid support.

Finally, the natural gas converted San Juan 5 retires in 2035, while San Juan 6 is retired earlier after 2025. Under the high and low load cases, the timing of the San Juan 5 retirement varies by a year or two but still in the 2030s.

Exhibit 8-45: ESM Capacity Retirements (last year in service shown)



Capacity by Technology MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PREPA Steam (HFO)	0	0	0	0	0	0	0	0	0	0
PREPA MATS Affected units remaining						0	0	0	0	0
PREPA Costa Sur (Gas)	0	782	0	0	0	0	0	0	0	0
PREPA Diesel CC & large GTs	0	0	200	0	82	0	257	0	0	0
PREPA CC-converted (Gas)	0	0	0	0	0	0	200	0	0	0
EcoElectrica	0	0	0	0	0	0	0	0	0	0
AES									417	0
Total Dependable Gen Retirement	**0**	**782**	**200**	**0**	**82**	**0**	**457**	**0**	**417**	**0**

8.3.3 Future Generation Mix and Reserves

During the planning, under the ESM portfolio, the system moves away primarily from coal and oil to natural gas, renewables and energy storage. By 2038, 62% of the installed capacity in the system consists of renewable generation or facilities in place for its integration (battery storage). This number includes customer driven distributed solar. However, total renewable generation is only 44% of the total compared to 63% in the S4S2 plan (see Exhibit 8-37). Most of the gas generation comes from the two new large CCGTs and EcoEléctrica. As such, the development of the LNG terminals is critical for the feasibility of the new gas units. As PREPA's units and the thermal PPOA's are phased out, the operating reserves decline from 71% in 2019 to a low of 56% by 2028 with the retirement of AES coal. Operating reserves rise gradually afterwards driven by the decline in load and the addition of battery storage to manage solar generation and reduce curtailments. The Planning Reserve Margin was not found to be binding at any time on the LTCE decisions.

Exhibit 8-46: ESM Future Installed Capacity Mix

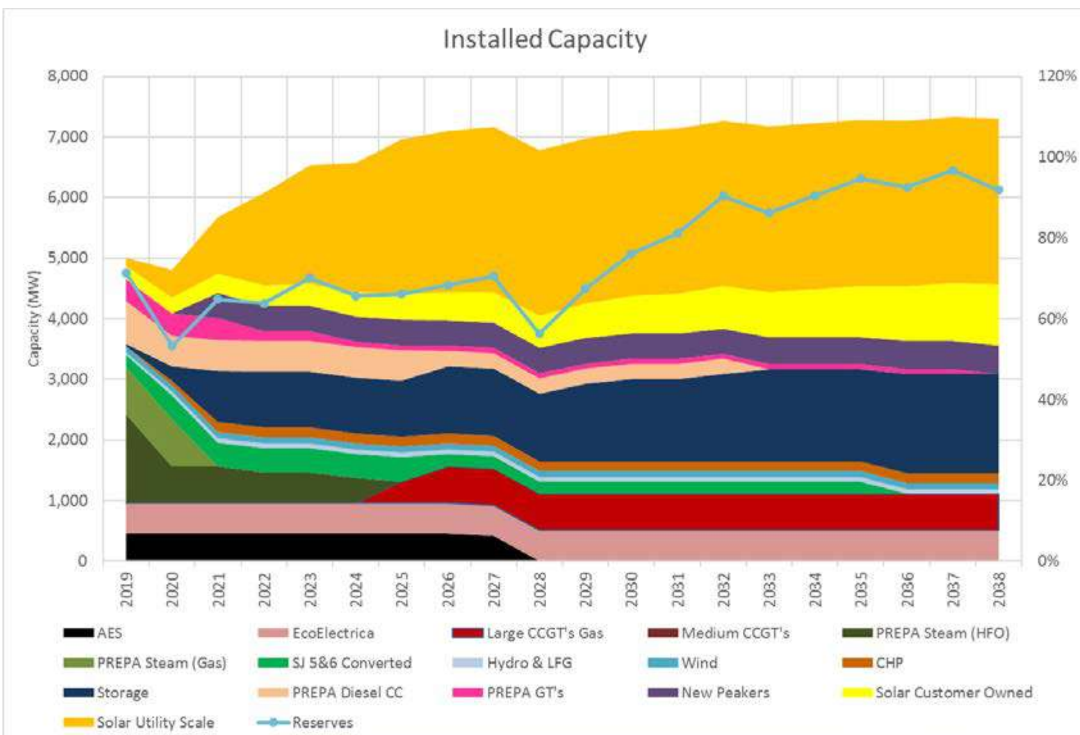
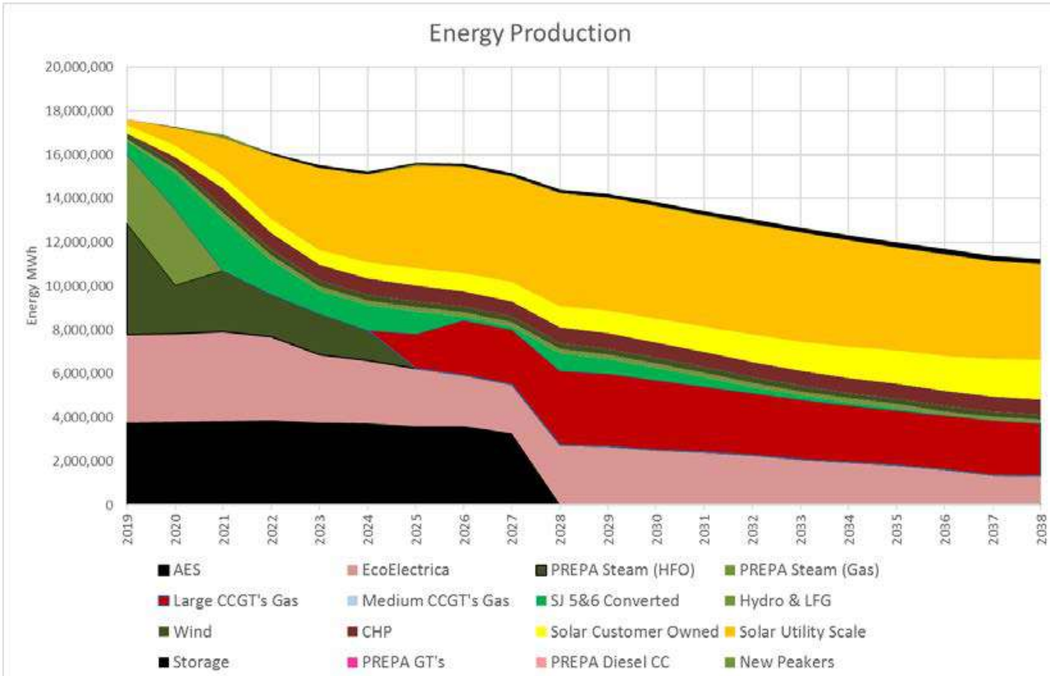


Exhibit 8-47: ESM Future Generation Mix

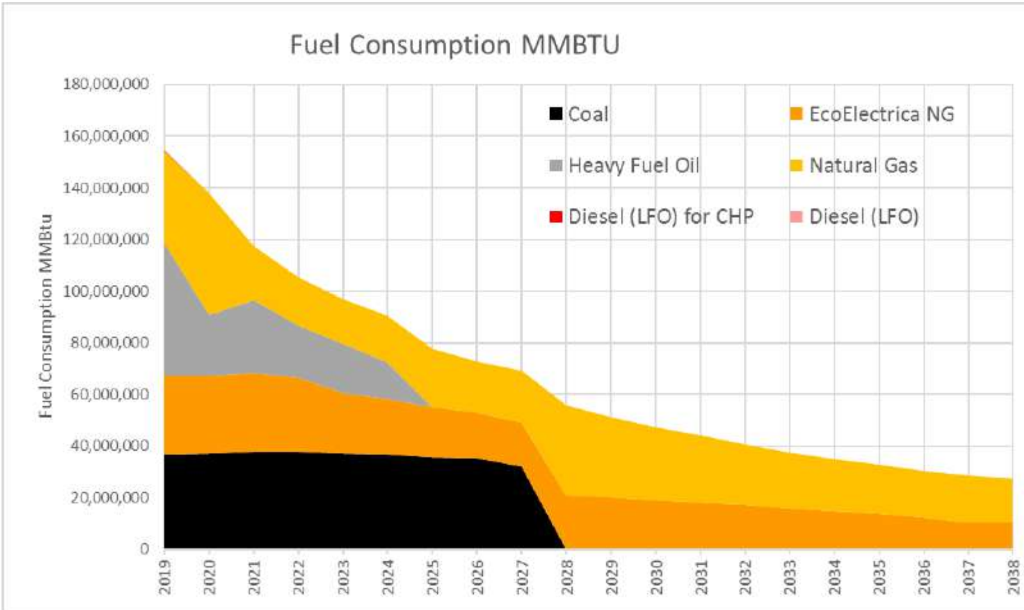


8.3.4 Fuel Diversity

In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas. There is a significant decline in the overall fuel consumption and associated costs with the implementation of the plan. Fuel consumption declines 82% by 2038 with the retirements of old Steam gas, heavy fuel oil and coal units.

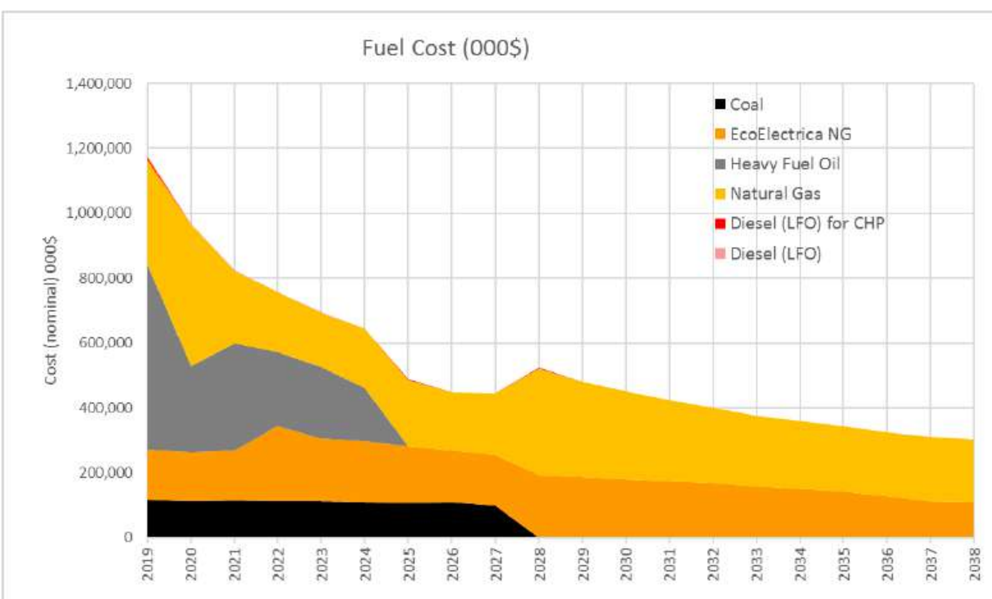
Fuel consumption is marginally higher (only 0.3%) compared to the least cost plan under Scenario 4.

Exhibit 8-48: ESM Plan Fuel Consumption



Fuel costs decline in line with the overall fall in fuel consumption falling to a low of $304million by 2038 (74% below 2019 levels) with all the retirements, including AES. Overall fuel costs are one half compared to February's filing. Under the high demand case, fuel costs are 8% higher compared to the base load case. In contrast, fuel costs are 11% lower under the low demand case.

Exhibit 8-49: ESM Plan Fuel Costs



8.3.5 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan and Base Load forecast from $102/MWh in 2019 to $97.0/MWh by 2025 (real $2018), primarily due to the retirement of older generation and the addition of solar and storage. The overall costs increase in 2028 due to rising fuel costs with higher generation from EcoEléctrica and San Juan unit 5, after the retirement of AES (despite the offset from AES costs). Production costs average $98.9/MWh for the first 10 years of the plan, 0.3% lower than the least cost plan under Scenario 4 portfolio (S4S2). In the last ten years of the plan, production costs average $106.8/MWh, 1.9% higher than the least cost plan under Scenario 4.

The net present value of all operating costs is $14.4 billion over the planning period, $81 million higher than the least cost plan under Scenario 4 Portfolio. Note that the 9% discount rate (6.86% on a real dollar basis), is the same discount rate used in the first IRP and it is based on the assumption that PREPA (or its successors) is able to resolve its current financial issues and can borrow the capital at this rate. It should not be confused with the WACC which the weighted cost of capital for private parties that are assumed to invest in the resource additions.

Under the high demand case, total system costs reach $15.25 billion, $823 million above the plan under base load, mostly driven by higher fuel costs and very close to S4S4 under similar conditions ($15.16 billion). Under the low demand case, total system costs are $479 million below the base load plan driven by lower generation and solar capital investments. Under low load the difference with the S4S2 increases $13.92 billion on the ESM versus $12.87 billion on the S4S2.

Exhibit 8-50: Production Costs

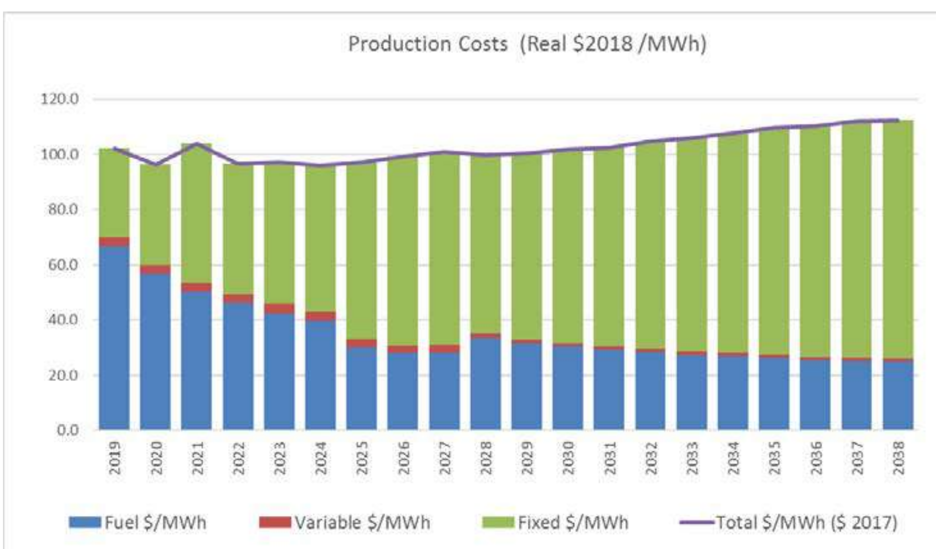


Exhibit 8-51: System Costs ESM Plan, High and Low Load Cases

Case ID	Scenario	Strategy	Sensitivity	Load	AURORA LTCE	NPV @ 9% 2019-2038 k$	Average 2019-2028 2018$/MWh	NPV Deemed Energy Not Served k$ (1)	NPV + ENS k$	Capital Investment Costs ($ Millions)
ESM				Base	Yes	14,431,214	99.0	266,947	14,698,161	5,556
ESM High				High	Yes	15,254,859	97.0	465,022	15,719,880	5,585
ESM Low				Low	Yes	13,952,366	105.0	202,453	14,154,819	4,779

8.3.6 Resiliency (Mini Grid Considerations)

In the ESM plan, the critical loads are fully met with local generation by 2021, however the balance of the load is not fully covered while the plan is being developed in 2019 through 2022. After 2022, it varies depending on the MiniGrid region.

Siemens estimated the costs from unserved energy in the case of a major hurricane impacting the transmission system[74]. It is assumed that a major hurricane occurs every five years impacting major interconnection transmission lines and placing the system into MiniGrids operation for 1 Month, starting in 2022. It is based on a $2000/MWh value for unserved energy, which considers that the load shedding will be rotated to minimize impact. The $2000 is consistent with the cost of unserved energy for residential customers[75].

Exhibit 8-22 summarizes the economic costs by MiniGrid region for the ESM plan. The largest potential costs are for San-Bayamon, Caguas, Carolina and Arecibo. Overall, there is an incremental 267 million in potential costs from unserved energy in the case of a major hurricane impacting the island under this plan. This compares to $247.5 million for the least cost plan under Scenario 4.

[74] This cost is NOT a forecast of future cost, but rather a high-level determination of how the different portfolios resulting from the combination of Scenarios and strategies would perform if every 5 years starting in 2022 a major hurricane impact the island resulting in the operation of the MiniGrids for one month (“Deemed Energy Not Served”)

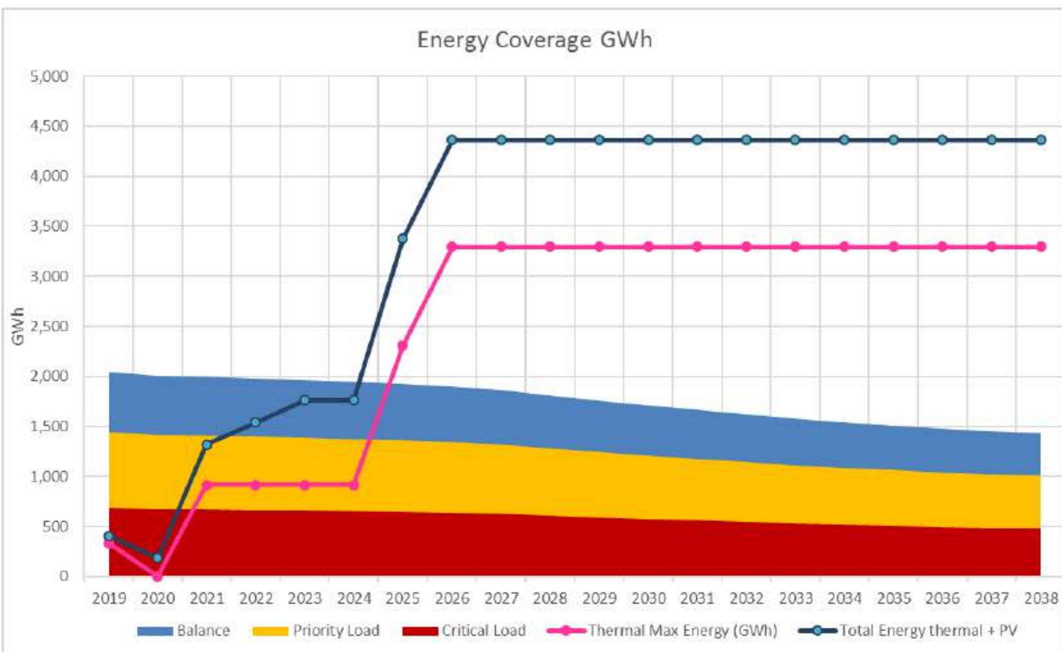
[75] This value is much lower compared to the VOLL determined for PR, in the range of $30,000/MWh

Exhibit 8-52: Cost of Energy Not Served by MiniGrids

MiniGrid	ESM NPV Cost ($000)	Scenario 4 NPV Cost ($000)
San Juan-Bayamon	$ 64,141	$ -
Ponce	$ -	$ -
Carolina	$ 66,615	$ 73,980
Caguas	$ 52,252	$ 87,124
Arecibo	$ 70,935	$ 79,405
Mayaguez-North	$ -	$ -
Mayaguez-South	$ 13,004	$ 143
Cayey	$ -	$ 6,792
Total	$ 266,947	$ 247,445

In Caguas, the total thermal energy available (inclusive of solar PV) covers the critical loads but not the priority loads through 2024 under the ESM case. The deployment of 115 MW of peakers (mobile) in 2021 seeks to cover the critical loads in this region under a MiniGrid operation (see Exhibit 8-43). The balance load is met in 2025 and onwards with the addition of a 302 MW F-Class CCGT in 2025 in Caguas. There is excess generation in this MiniGrid region afterwards.

Exhibit 8-53: Caguas Energy Coverage under a Minigrid Operation

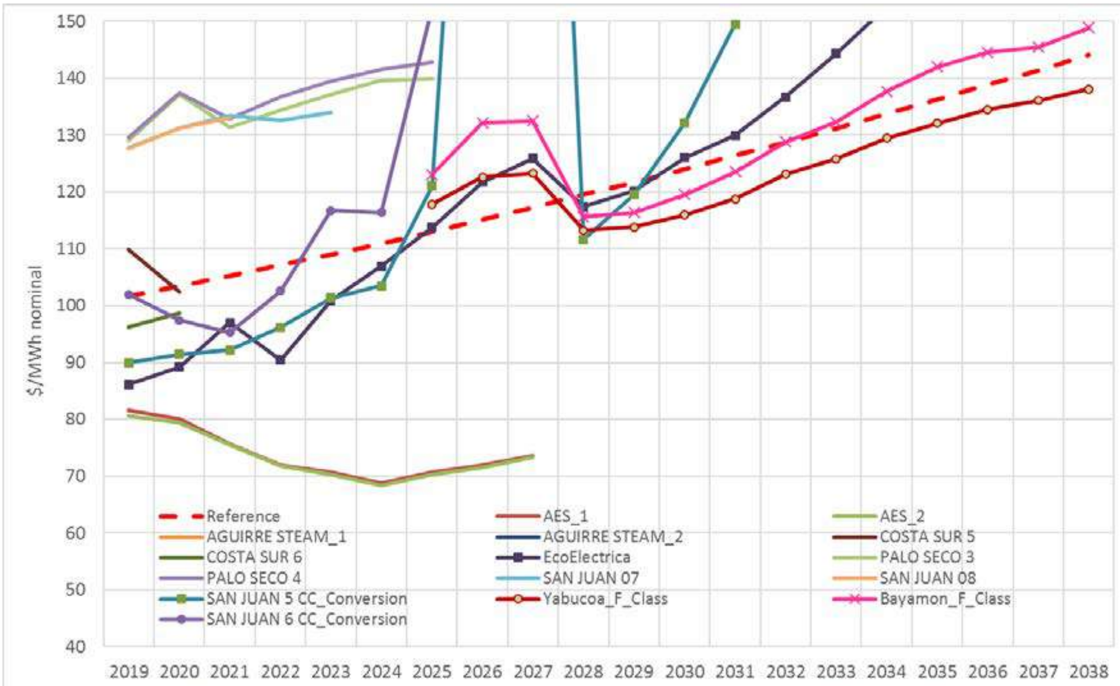


8.3.7 High Efficiency Requirement Fossil Generation

For demonstration of compliance with the High Efficiency Requirement, the levelized costs in $/MWh for new and existing CCGTs staying online meet the 100$/MWh requirement escalated at the inflation rate (i.e. in nominal terms), as shown in the exhibit below. The new CCGTs close to the $100/MWh (adjusted to nominal terms) requirement through the study period. San Juan conversions 5 & 6 stay below the requirement for the beginning of the

analysis. San Juan 5 & 6 exceeds the requirements prior to its retirement and in some years when capacity factors go below 50%.

Exhibit 8-54: ESM High Efficiency Requirements



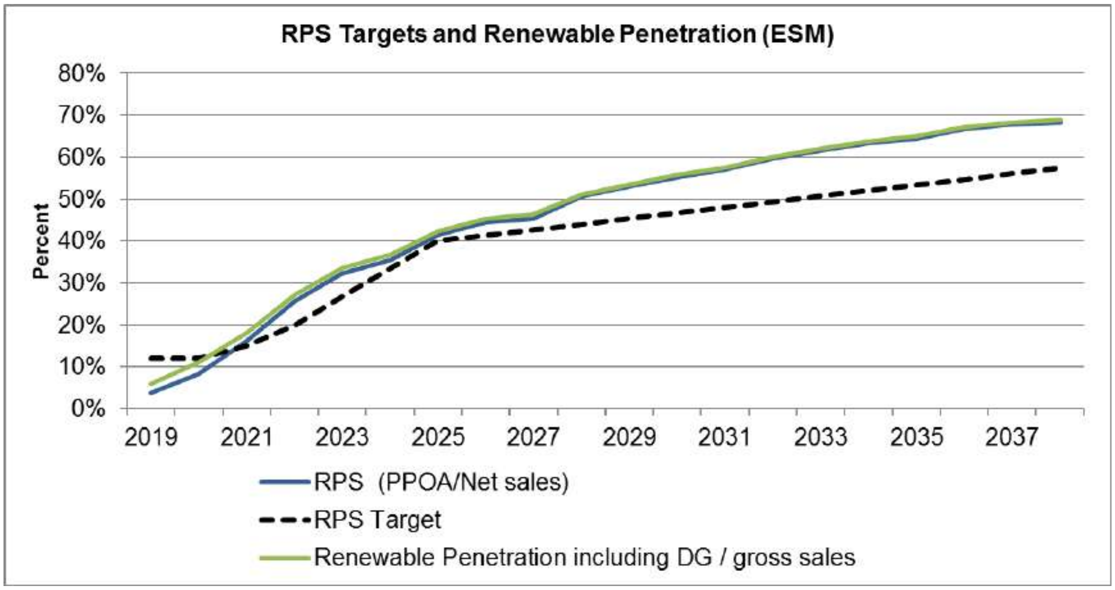
8.3.8 RPS and Environmental Compliance

8.3.8.1 Renewable Compliance

The ESM plan is MATS compliant after 2024 and achieves 67% RPS compliance by 2038 under the base case load forecast (53% under high load and 54% under low load growth).

The renewable portfolio standard targets of 15% by 2021, 20% by 2022 and 40% by 2055 are all met in the ESM Plan under all load cases. The levels of renewable penetration exceed a linear trend towards the 60% renewable target by 2040, with the plan meeting or exceeding the target by 2038 in all load cases.

Exhibit 8-55: Renewable Portfolio Standards



8.3.8.2 Environmental Progress

CO2 emissions for PREPA's fleet fall in the first ten years of the forecast driven by the retirement of the older fuel oil, diesel and gas units along with increased penetration of solar generation. Emissions fall 52% by 2027 and further by 75% a year later with AES coal retirement in 2028. Emissions continue falling but more gradually after 2028 reaching an 87% reduction by 2038. The emission rate for the fleet falls from 1,351 lbs./MWh in 2019 to 365 lbs./MWh in 2038. Total emissions under the ESM plan are fairly similar to the least cost plan under Scenario 4.

The new CCGTs have the lowest emission rates at 820 lbs./MWh. San Juan units converted to natural gas also show low emissions rates at around 850 lbs./MWh. EcoEléctrica is also a low emitter at 877 lbs./MWh. The unit with the highest CO2 emission rates is AES coal at 2,161 lbs./MWh, prior to retirement.

Exhibit 8-56: CO2 Emissions PREPA System

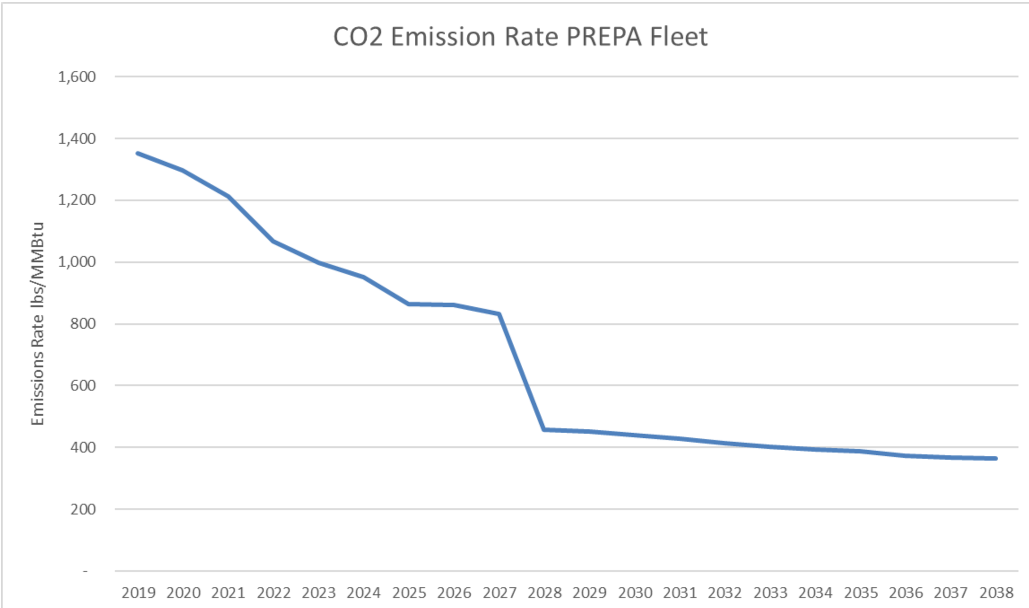


Exhibit 8-57: CO2 Emissions by Unit Type

Summary by Tech										
lb/MWh	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
AES	2,156	2,156	2,154	2,154	2,156	2,157	2,159	2,160	2,161	-
EcoElectrica	877	877	876	879	879	879	880	881	882	880
Costa Sur 5&6	1,248	1,254	-	-	-	-	-	-	-	-
Existing Fleet (HFO)	1,417	1,723	1,682	1,697	1,706	1,690	1,679	-	-	-
Diesel CC (LFO)	632	1,335	1,333	1,335	1,335	1,335	1,335	1,335	1,333	1,326
Existing GTs (LFO)	1241	1239	1041	0	0	0	0	0	0	0
SJ 5&6 With NG	865	858	854	851	848	848	849	840	839	839
New CCGT's Gas	0	0	0	0	0	0	804	805	805	819
New CCGT's Diesel	0	0	0	0	0	0	0	0	0	0
New Peaker gas	0	0	1189	1181	1166	1169	1185	1165	1185	1174
New Peaker diesel	0	0	0	0	0	0	0	0	0	0
Total ESM	**1,351**	**1,298**	**1,214**	**1,069**	**997**	**952**	**865**	**861**	**832**	**457**

8.3.9 Sensitivities Consideration

The Siemens team run three sensitivities for the ESM case, including a high and low cost of renewables and a high gas price sensitivity. The ESM case is more sensitive to higher costs of renewables than lower cost with the NPV of costs increasing by $1.2 billion compared to a reduction of $300 million under the low cost of renewables sensitivity; this is the case for all scenarios as there greater spread on higher prices than lower. As requested by PREB under the April 2019 Order, the sensitivities were performed without changing the expansion plan. Under a high gas price sensitivity the NPV of costs increase by $1.2 billion.

Exhibit 8-58: EMS with 50% RPS Sensitivity System Costs

Case ID	Scenario	Strategy	Sensitivity	Load	AURORA LTCE	NPV @ 9% 2019-2038 k$	Average 2019-2028 2018$/MWh	NPV Deemed Energy Not Served k$ (1)	NPV + ENS k$	Capital Investment Costs ($ Millions)
ESM				Base	Yes	14,431,214	99.0	266,947	14,698,161	5,556
ESM High				High	Yes	15,254,859	97.0	465,022	15,719,880	5,585
ESM Low				Low	Yes	13,952,366	105.0	202,453	14,154,819	4,779
ESMS1B			1	Base	No	14,121,243	97.1	266,947	14,121,340	5,556
ESMS6B			6	Base	No	15,592,035	106.3	266,947	15,592,141	5,556
ESMS5B			5	Base	No	15,612,073	106.9	266,947	15,612,180	5,556

8.3.10 Rate Impact

In the sections above, we presented the composition of least cost portfolio formulated under the Energy System Modernization (ESM) Plan Base Case.

In this section, similar to the calculations for Scenario 4, we estimate the potential impact of the ESM portfolio on the final rates to customers; and compare the resulting final rates with the possible costs that the customers would incur for self-supply and other customer based alternatives.

The comparison is made considering the "Rate Components" presented earlier (see section 8.2.12.1)

8.3.10.1 Results of Comparison to Customer Based Alternatives

In this section we describe the results of the analysis we performed comparing the final ESM rates to unit costs for customer based alternatives.

The ESM generation portfolio costs are similar to the S4S2 portfolio and the conclusions are the same. The comparison analysis results are illustrated in Exhibit 8-48, and are summarized below:

- The levelized cost of customer alternatives (especially Solar PV and Grid Defection) is higher than the cost of the generation delivered to the customer and that includes the effect of losses until 2028 (when AES Coal retires). However, this cost is significantly lower than the total rate and confirms the assumption in the DG forecast that the continuance of 'net-metering' rates will occur, and the customer side roof top PV adoptions will continue to be in line with the high adoption rates observed to date.
- These results also indicate that the customers may be motivated to self-supply if they are able to raise the capital investment required for installing the self-supply option or if a developer installs the equipment and recovers the investment through leases or other financing options.

We analyzed another case where we reduced the non-technical losses to typical values observed in the US (0.5% or less). Note that the distribution technical losses are within the expected values of PREPA's peers and account for the reduction in losses due to the increased penetration of distributed generation. Keeping all else the same, the resulting final rate for the ESM generation portfolio, also reduces, but not to the extent that our above

observations and inferences change. This updated comparison chart is given in the exhibit below.

Exhibit 8-59: Final ESM Generation Portfolio Rates Compared to Unit Costs of Customer Alternatives

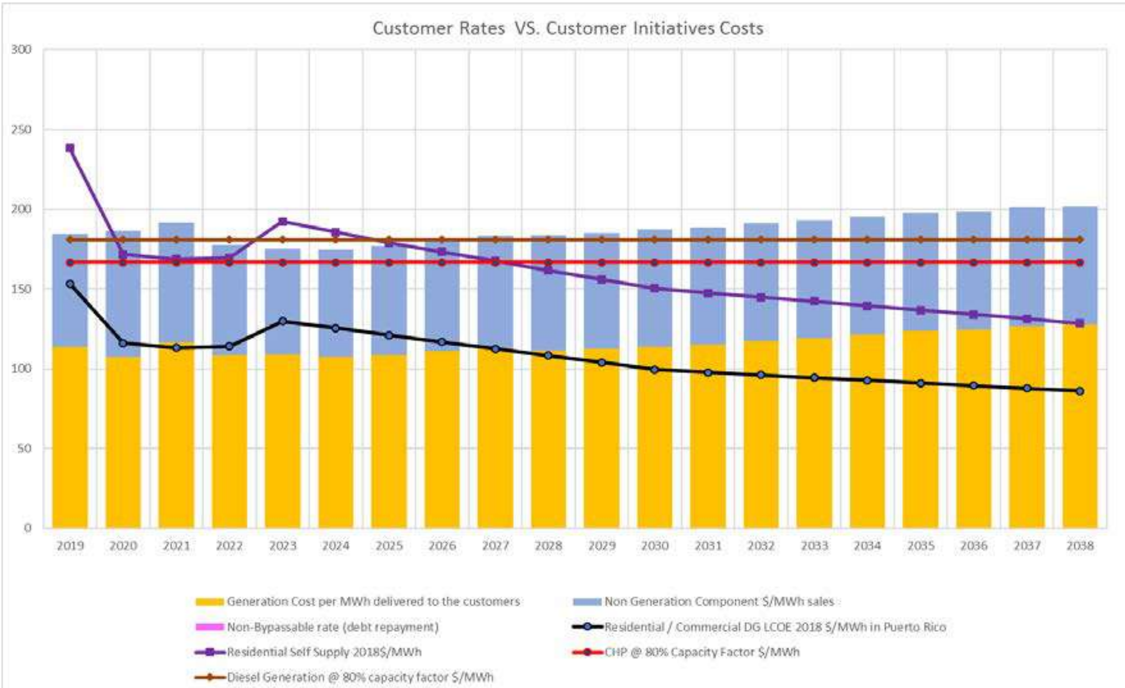
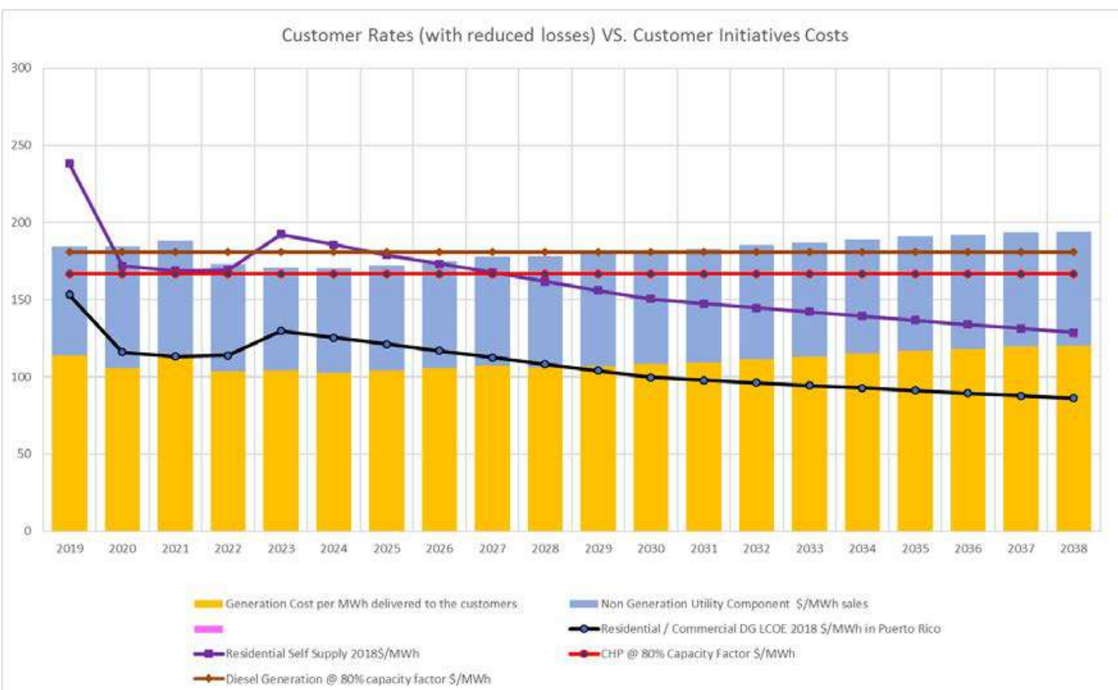


Exhibit 8-60: Final ESM Generation Portfolio Rates Assuming Reduced Losses



8.3.11 Nodal Analysis of the ESM

As was the case of Scenario 4, we analyzed the ESM using a nodal simulation. The objective again was to identify the effects of transmission on the key metrics of technical losses, production costs, renewable curtailment and energy not served.

The results of the nodal runs show the production costs of the nodal runs match very closely with those of the zonal runs used for the LTCE assessment for the entire period see exhibit below. As before the transmission losses in the system were confirmed to be very low starting in the 1.1% range and dropping to 0.5% for most of the planning period.

There was no energy not served in the nodal runs, which is in line with the results of the zonal runs.

In summary the minimal impact of transmission was expected due to the greater distribution of generation resources and reduced load.

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Exhibit 8-61: Production Costs Nodal vs. Zonal and Renewable Curtailment

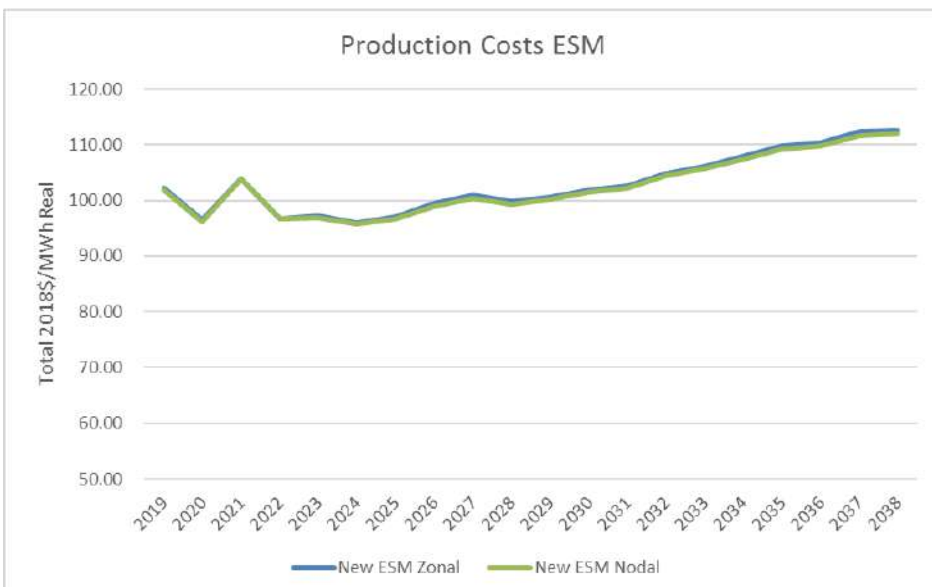


Exhibit 8-62: Transmission Losses

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1.1%	1.0%	0.7%	0.7%	0.6%	0.6%	0.6%	0.7%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%

8.4 Scenario 1 Results

Scenario 1 is a portfolio in which there no new LNG terminals can be developed in the island; with the exception of the ongoing project to supply the conversion of San Juan 5&6. Only the existing gas at the Cost Sur LNG terminal is available to supply the existing generation infrastructure but no new gas generation can be added.

The Scenario also considers that the base case assumptions for solar and storage costs and availability.

Scenario 1 was simulated under the base high and low load forecast and under three strategies, strategy 2 (decentralized 80% of demand met by local resources base case), strategy 3 (50% of demand met with local generation) and strategy 1 (centralized system).

Three sensitivities were run also with this Scenario; Sensitivity 1; low cost of renewable generation, Sensitivity 5 high price of gas, Sensitivity 6 high cost of renewable generation and Sensitivity 7; no development of the conversion of San Juan 5&6.

In general Scenario 1 result in a plan that has higher production costs compared to other plans including Scenario 4 and the ESM, but not as much in the prior filings of this IRP, as the levels of renewable generation are similar. Most of the increase in costs comes from higher fuel costs as the plan does not allows for the incorporation of new CCGT's and in some cases it requires the use of Costa Sur 5&6 for longer periods of time (i.e. until the load declines to levels that it can be retired). The reduced need for utility scale renewable is probably correlated with the reduced load from 2030 onwards that would reduce the value of this generation if it were to be installed earlier on.

Resiliency at the MiniGrid level is comparable to the Scenario 4.

Exhibit 8-54 below provides a summary of the investments results for Scenario 1 and the key cost metrics in comparison with the S4S2 and the ESM case.

Exhibit 8-63. Scenario 1 Summary of results and comparison with Scenario 4 and ESM

	Large & Medium CCGTs and Peakers							Renewable and Storage				
Case ID	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peker Conversion	Other	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)	Customer Owned Generation 2038 (MW)
S1S2B	–	EcoEléctrica Instead	✔	–	–	–	504	2,580	1,280	2,700	1,720	1,176
S1S2H	–	EcoEléctrica Instead	✔	–	–	Costa Sur 5 to 2034	325	2,820	1,360	3,180	1,840	1,176
S1S2L	–	EcoEléctrica Instead	✔	–	–	–	325	2,340	1,240	2,340	1,800	1,176
S1S3B	–	EcoEléctrica Instead	✔	–	–	–	513	2,580	1,280	2,580	1,840	1,176
S1S2S1B	–	EcoEléctrica Instead	✔	–	–	–	504	2,580	1,280	2,700	1,720	1,176
S1S2S5B	–	EcoEléctrica Instead	✔	–	–	–	504	2,580	1,280	2,700	1,720	1,176
S1S2S6B	–	EcoEléctrica Instead	✔	–	–	–	504	2,580	1,280	2,700	1,720	1,176
S1S2S7B	–	EcoEléctrica Instead	–	–	–	Costa Sur 5 to 2036	507	2,880	1,280	3,240	1,760	1,176
S1S1B	–	EcoEléctrica Instead	✔	–	–	Costa Sur 5&6 to 2037 & 2031	301.6	2,520	1,240	2,520	2,080	1,176
S4S2B	✔	✔	✔	–	–	–	371.2	2,220	1,320	2,820	1,640	1,176
ESM	✔	EcoEléctrica Instead	✔	✔	✔	–	421	2,400	920	2,580	1,640	1,176

	Central Metrics							
Case ID	**NPV @ 9% 2019-2038 k$**	**Average 2019-2028 2018$/MWh**	**RPS 2038**	**NPV Deemed Energy Not Served k$ (1)**	**NPV + ENS k$**	**Lowest Reserve Margin**	**Emissions Reductions**	**Capital Investment Costs ($ Millions)**
S1S2B	14,773,629	102.2	54%	214,355	14,941,402	38%	96%	5,840
S1S2H	16,134,592	101.4	68%	392,504	16,527,096	36%	94%	5,857
S1S2L	13,535,576	101.3	68%	263,997	13,799,572	37%	99%	4,684
S1S3B	14,687,535	101.8	54%	485,666	15,173,201	33%	97%	5,560
S1S2S1B	14,449,784	100.1	54%	214,355	14,617,557	38%	96%	5,293
S1S2S5B	15,378,227	106.0	54%	214,355	15,546,000	38%	96%	5,840
S1S2S6B	16,018,738	110.2	54%	214,355	16,186,511	38%	96%	7,898
S1S2S7B	15,696,705	106.8	68%	422,543	16,119,248	44%	96%	6,606
S1S1B	14,366,811	98.4	68%	1,150,508	15,517,319	35%	96%	5,546
S4S2B	14,350,195	99.3	68%	247,445	14,597,640	42%	86%	6,595

As can be observed the Scenario 1 has worse cost performance than the ESM and Scenario 4 due to the increased use of peaking generation, mode BESS and greater fuel consumption on the existing generation fleet particularly the Mayaguez peakers, and the new LFO fired peakers, EcoEléctrica, the San Juan 5&6 conversion and the Costa Sur units have to be extended in some cases. In summary the lack of gas assumed by this Scenario is resulting in greater burn of less clean fuels.

8.4.1 Capacity Additions and Retirements for Scenario 1

The economic simulation of Scenario 1, Strategy 2 Base load (S1S2B) forecast 2,700 MW of utility scale PV additions over the study period with 2580 MW added in 2019-2025, maximizing solar PV capacity additions in the short to medium term. All solar PV additions

happen in the first 10 years of the plan. The high load case for Strategy 2 adds 3,180 MW of in total and requires Costa Sur 5 to continue operations until 2034. The low load case for Strategy 2 adds 2,340 MW in total. Under strategy 3, solar additions are similar (see Exhibit 8-54).

The case requires somewhat higher values of BESS than the ESM or S3S2 in the long term (1,7020 MW versus 1,640 MW).

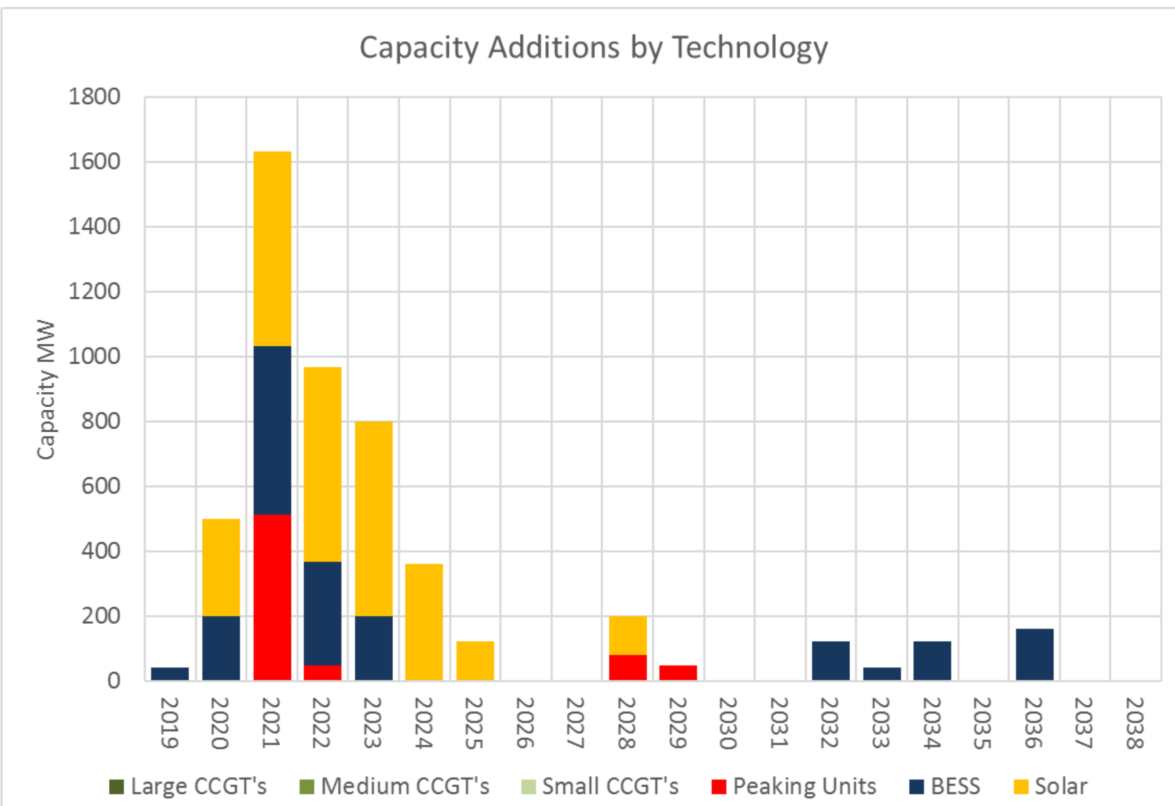
The need for peaking capacity is much larger compared to ESM Scenario 4 661 MW over the planning period, versus 372 MW in the S4S2 and 421 in the ESM. The actual dispatch of this units is also much higher leading to the cost increase mentioned

Under strategy 1 (a centralized plan), the expansion plan relies on the extension of Costa Sur 5&6 to 2037 and 231 and is much less resilient to disruptive hurricane events (see Exhibit 8-54).

The plan is MATS compliant after 2024 and achieves 54% RPS compliance by 2038.

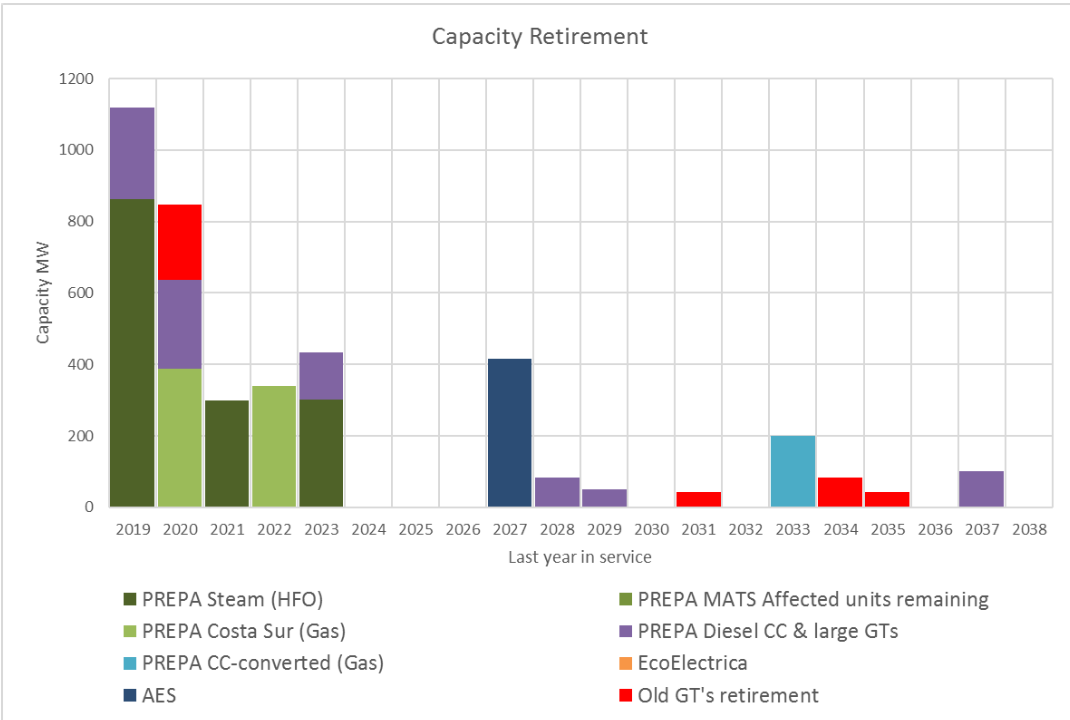
The exhibit below provides the capacity additions of S1S2 under base load forecast followed by the retirements. Here we note that all steam HFO fire fleet is retired by 2024 (2023 last year in service), but for example the old CT's at Palo Seco and Vega Baja are maintained by the plan over the long term to provide needed reserves in the north.

Exhibit 8-64: Scenario 1 Base Load Capacity Additions



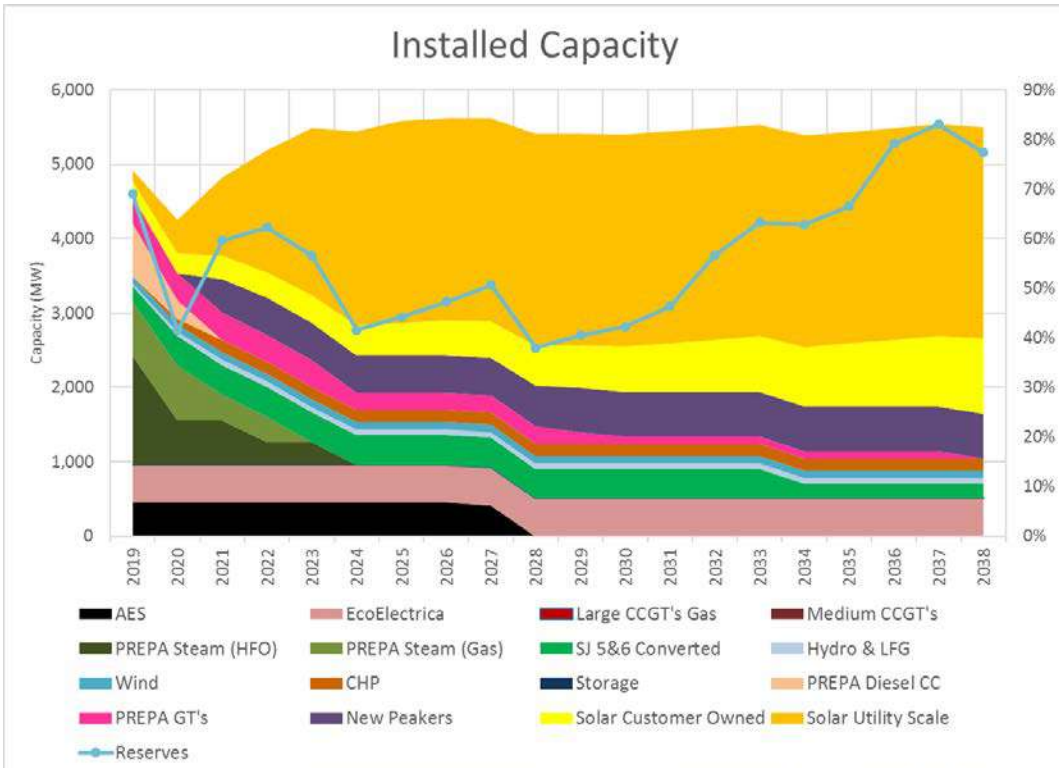
Technology / MW		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total
Large CCGT's		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Medium CCGT's		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small CCGT's		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Peaking Units		0	0	513	46	0	0	0	0	0	78	46	0	0	0	0	0	0	0	0	0	684
BESS		40	200	520	320	200	0	0	0	0	0	0	0	0	120	40	120	0	160	0	0	1720
Total Distchable Additions		40	200	1033	366	200	0	0	0	0	78	46	0	0	120	40	120	0	160	0	0	**2404**
Solar		0	300	600	600	600	360	120	0	0	120	0	0	0	0	0	0	0	0	0	0	2700
New Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Additions		40	500	1,633	966	800	360	120	0	0	198	46	0	0	120	40	120	0	160	0	0	**5,104**

Exhibit 8-65: Scenario 1 Base Load Capacity Retirements



Technology / MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Total
PREPA Steam (HFO)	862	0	300	0	301	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1463
PREPA MATS Affected units remaining						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PREPA Costa Sur (Gas)	0	388	0	339	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	728
PREPA Diesel CC & large GTs	257	249	0	0	132	0	0	0	0	82	50	0	0	0	0	0	0	0	100	0	871
PREPA CC-converted (Gas)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200	0	0	0	0	0	200
EcoElectrica	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AES									417	0	0	0	0	0	0	0	0	0	0	0	417
Total Dependable Gen Retirement	**1119**	**637**	**300**	**339**	**434**	**0**	**0**	**0**	**417**	**82**	**50**	**0**	**0**	**0**	**200**	**0**	**0**	**0**	**100**	**0**	**3678**
Note: For retirement last year in service shown																					
Old GT's retirement	0	210	0	0	0	0	0	0	0	0	0	0	42	0	0	84	42	0	0	0	378

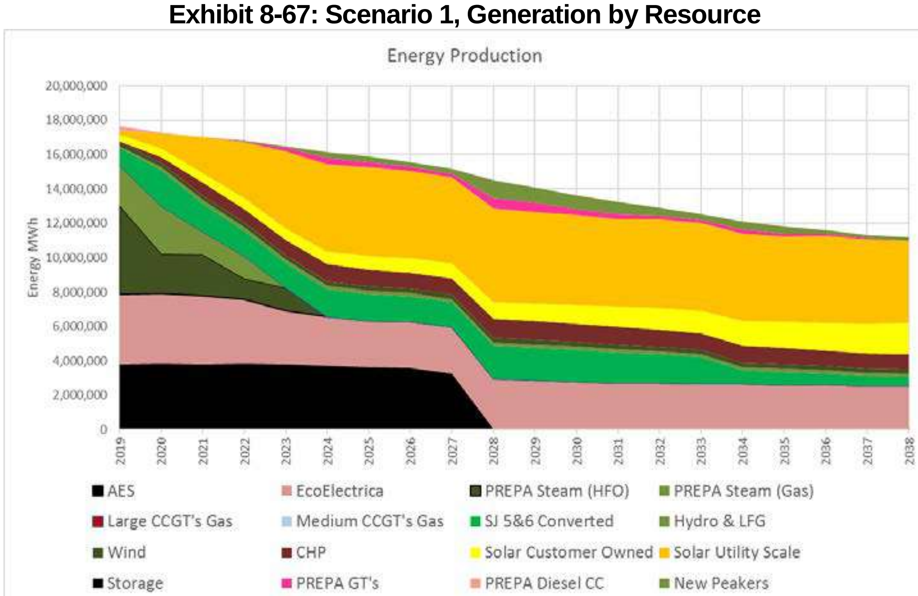
Exhibit 8-66: Scenario 1, Future Capacity Mix



As PREPA's units and the thermal PPOA's are phased out, the operating reserves decline from 70% in 2019 to a low of 42% by 2025. The Planning Reserve Margin of 30% appears not to have been binding constraint on the LTCE plan formulation in this Scenario.

Below we observe the generation by resource and we note the impact of existing GT's and new LFO fired peakers in the supply

Exhibit 8-67: Scenario 1, Generation by Resource



8.4.2 Fuel Diversity

In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas and diesel along with a sharp drop in overall fuel consumption and associated costs with the implementation of the plan. By 2038, 80% of the generation is coming from renewables. However, we note a heavier participation of Light Fuel Oil in the fuel mix, that in some critical year like 2028, right after the retirement of AES reaches 34% of the fuel consumed and 11% of the total energy delivered comes from GT's burning this fuel.

Exhibit 8-68: Scenario 1 Fuel Consumption

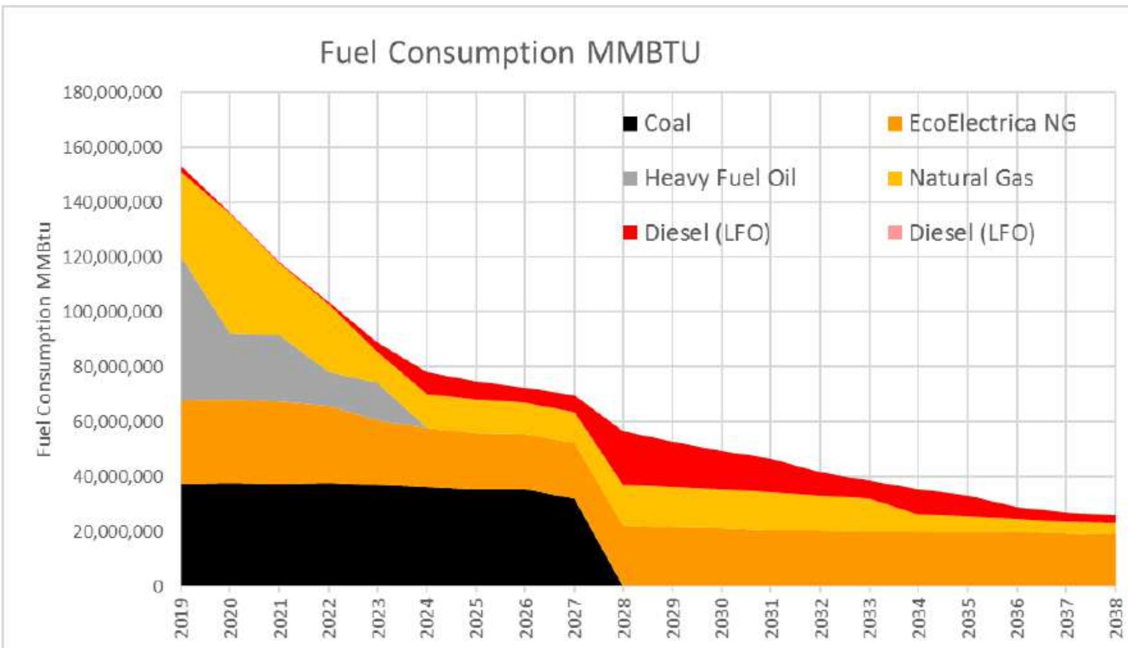
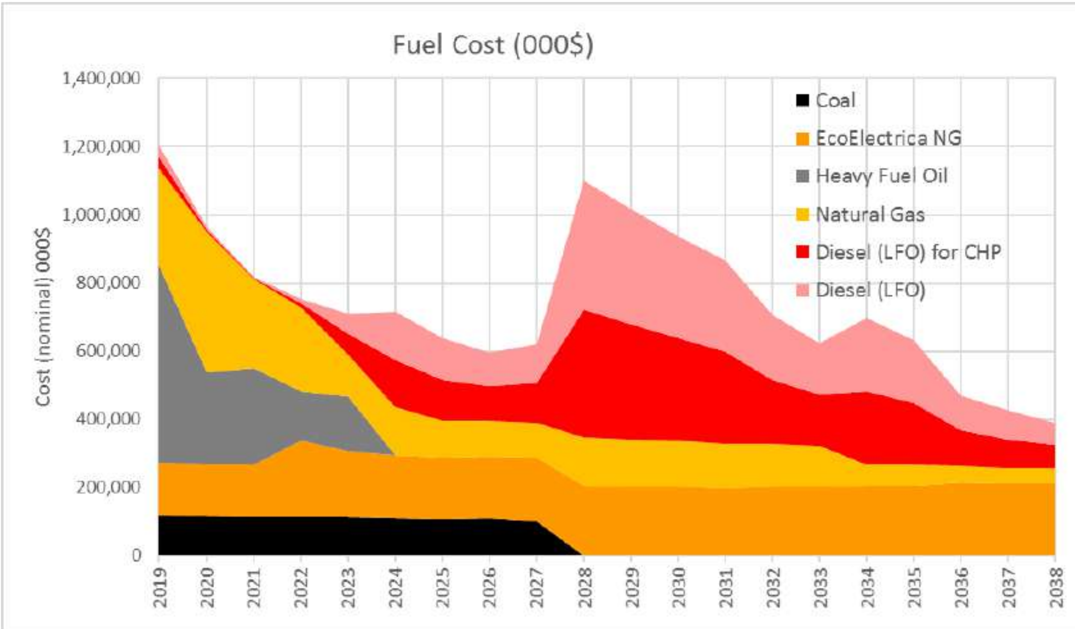


Exhibit 8-69: Scenario 1 Fuel Costs

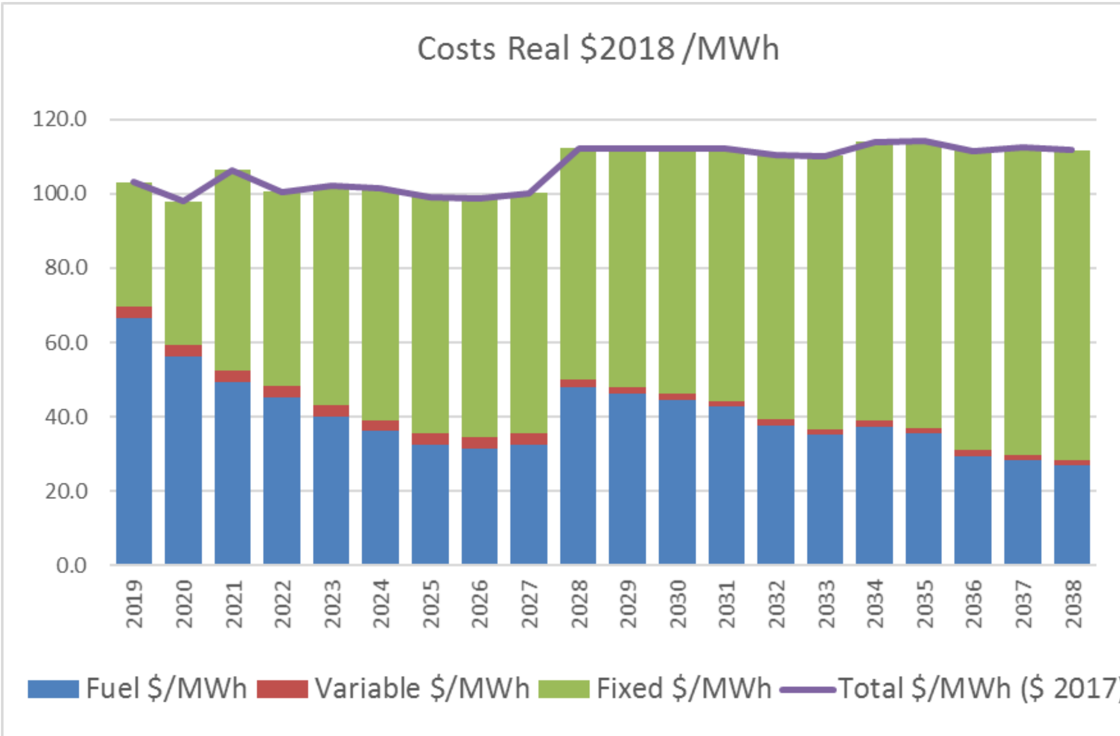


8.4.3 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan from $ 103./MWh in 2019 to $98.71/MWh by 2026 (real $2018), prior to AES Coal retirement, with the addition of solar and storage and the retirement of older generation. The costs increased in 2028 to $112.3/MWh as AES retires and there is heavier use of the remaining thermal generation. The, system costs basically remain constant reaching 1$111.8/ MWh by 2028.

The net present value of all operating costs reaches $10.9 billion for 2019-2028 (nominal @ 9% rate). Over the study period, the NPV is $14.77 billion. This plan is $342 million more expansive compared to ESM Case and $ 423.4 million more expensive than the S4S2.

Exhibit 8-70: Scenario 1 Production Costs



Case ID	NPV @ 9% 2019-2038 k$	Average 2019-2028 2018$/MWh	RPS 2038	NPV Deemed Energy Not Served k$ (1)	NPV + ENS k$	Lowest Reserve Margin	Emissions Reductions	Capital Investment Costs ($ Millions)
S1S2B	14,773,629	102.2	54%	214,355	14,941,402	38%	96%	5,840
S1S2H	16,134,592	101.4	68%	392,504	16,527,096	36%	94%	5,857
S1S2L	13,535,576	101.3	68%	263,997	13,799,572	37%	99%	4,684
S1S3B	14,687,535	101.8	54%	485,666	15,173,201	33%	97%	5,560
S1S2S1B	14,449,784	100.1	54%	214,355	14,617,557	38%	96%	5,293
S1S2S5B	15,378,227	106.0	54%	214,355	15,546,000	38%	96%	5,840
S1S2S6B	16,018,738	110.2	54%	214,355	16,186,511	38%	96%	7,898
S1S2S7B	15,696,705	106.8	68%	422,543	16,119,248	44%	96%	6,606
S1S1B	14,366,811	98.4	68%	1,150,508	15,517,319	35%	96%	5,546

8.4.4 Resiliency (MiniGrid Considerations)

Scenario 1 is very similar to Scenario 4 with respect of resiliency assessed using the "Deemed Energy Not Served", which is shown in the next exhibit by MiniGrid and compared with Scenario 4 Strategy 2 for the base load forecast.

Exhibit 8-71: Present Value of Cost of Deemed Energy Not Served by MiniGrids

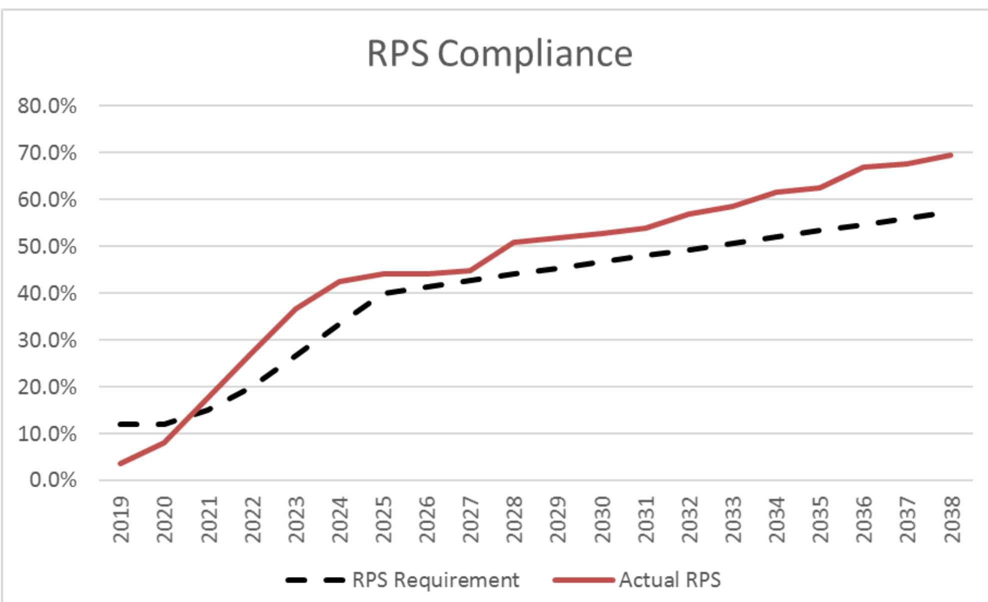
MiniGrid	S1S2B	S4S2B
San Juan-Bayamon	$ 46,582	$ -
Ponce	$ -	$ -
Carolina	$ -	$ 73,980
Caguas	$ 137,722	$ 87,124
Arecibo	$ 12,546	$ 79,405
Mayaguez-North	$ 17,362	$ -
Mayaguez-South	$ 143	$ 143
Cayey	$ -	$ 6,792
Total	$ 214,355	$ 247,445

As can be observed the levels of present value of the "Deemed Energy Not Served" are similar, however we see that we have energy not served in San Juan – Bayamon that did not happen under Scenario 4 and there is an increase in Caguas.

8.4.5 RPS Compliance

The plan complies with the RPS standard after 2021 as shown below.

Exhibit 8-72: Scenario 1 RPS Compliance



8.4.6 Sensitivity Considerations

The Siemens team evaluated a number of sensitivities as presented earlier.

A reduction on the Renewable costs would result in a reduction in the NPV of 2% or about $323 million. An increase in gas prices as was the case with all other scenarios resulted in an increase in costs of $604 million or 4% increase. The greatest impact by far is the situation where the cost of renewable increase and in this case the NPV increases by 8% or $ 1,245 million. Finally, if the San Juan LNG terminal were not developed there would be a severe impact and the NPV would increase by 6% or $933 million. See Exhibit 8-54 for details and the Scenario 1 workpapers.

8.4.7 Nodal Analysis of the S1S2B

The Siemens team evaluated the least cost plan under Scenario 3 using a nodal simulation to identify the effects of transmission on the key metrics of congestion, technical losses, production costs, renewable curtailment and energy not served.

The results of the nodal runs show that through the planning period, the production costs of the nodal runs match very closely with those of the zonal runs used for the LTCE assessment (see Exhibit below). The transmission technical losses, that were not considered in the zonal runs, but are assessed in the nodal are fairly low starting from about 1.1% dropping to 0.5% by 2029

The amount of curtailment observed for the new solar generation was lower in the Nodal runs as shown in below, which confirms that transmission is not expected to create curtailment.

There was no energy not served in the nodal runs, which is in line with the results of the zonal runs.

In summary the minimal impact of transmission was expected due to the greater distribution of generation resources and reduced load.

Exhibit 8-73: Production Costs Nodal vs. Zonal and Renewable Curtailment

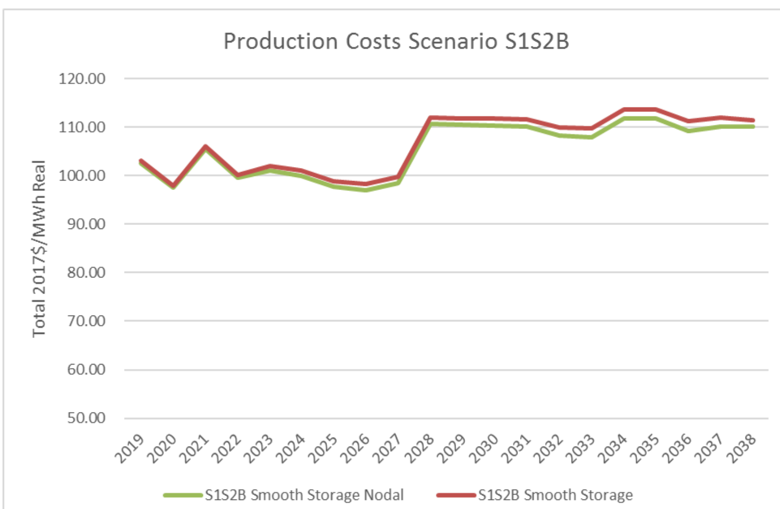
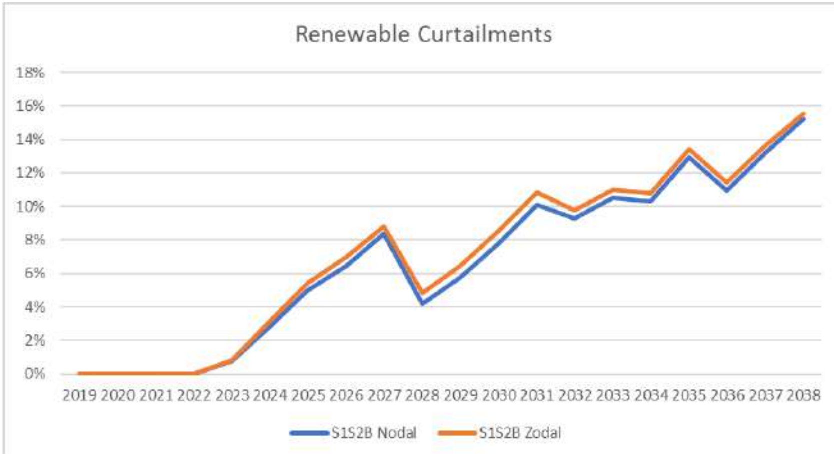


Exhibit 8-74: Renewable Curtailment



8.5 Scenario 3 Base Case Results

8.5.1 Capacity Additions and Retirements

The generation portfolio identified as Scenario 3 Strategy 2 (S3S2) result in a plan that has lower production costs as compared to the Scenario 4 and the ESM. The portfolio has a good balance of resources for a distributed system on a minigrid level capable of supplying the critical and priority loads for the customer in an event of a major disruptive hurricane.

However, the implementation of 4,140 MW of solar in a system with a 2,200 MW peak demand would be a significant challenge and could be difficult to achieve for practical reasons. The operation of the system would be a challenge with such a high level of solar penetration and its natural variability, increasing the risk of curtailment (that would negate some of the perceived economies) and putting strain and reliance on the energy storage.

The Scenario assumes lower capital investment costs for solar and storage (NREL Low Case) coupled with high availability of renewables (early ramp up). It also assumes gas available at Yabucoa (east) and Mayagüez (west) through ship-based LNG, in addition to gas to the north supplied through land-based LNG at San Juan. The land-based LNG at San Juan is assumed to acquire the required permitting approvals.

The economic simulation of the Scenario 3 case results in 4,140 MW of utility scale PV additions over the study period with 2,820 MW added as soon as 2022 (the maximum available). Solar installations are 1,320 MW larger compared to Scenario 4. The amount of solar capacity additions varies depending on the load forecast with 4,560 MW under a high load case and 4,080 MW under a low load case. If the Scenario is simulated under Strategy 3, solar installations are equivalent to Strategy 2 under a base load case (see Exhibit: 8-63). The Plan also builds 330 MW of wind, all in 2038 as the capital costs for wind become as competitive to solar PV, under this scenario.

Due to the higher renewable penetration, there is a larger need for peaking capacity to balance the system with 3,000 MW of battery energy storage built over the study period, with less than half in 2019-2025. A second batch of storage is installed after AES

retirement with an increasing need to manage the rising solar installation and curtailments in the 2030s.

Only one large CCGTs is installed in Costa Sur (302 MW), under the base and high load cases. Under the low load case, there is no new CCGTs installed.

San Juan units 5 & 6 converted to natural gas in 2019, with San Juan 5 retired economically in 2033 and San Juan 6 in 2030. EcoEléctrica is retired in 2024, in line with Scenario 4. The plan also builds 357 MW of peakers, similar to Scenario 4.

The plan is MATS compliant after 2024 and achieves 87% RPS compliance by 2038 (much higher than the Scenario 4 portfolio) as a result of lower costs for renewables and higher availability.

Exhibit: 8-75: Scenario 3 Results

						Large & Medium CCGTs and Peakers							Renewable and Storage				
Case ID	**Scenario**	**Strategy**	**Sensitivity**	**Load**	**AURORA LTCE**	F - Class Palo Seco 2025	F - Class Costa Sur 2025	San Juan 5&6 Conversion	F-Class Yabucoa 2025	Mayaguez Peker Conversion	Other	Peakers 2025 (MW)	New Solar 2025 (MW)	BESS 2025 (MW)	New Solar 2038 (MW)	BESS 2038 (MW)	Customer Owned Generation 2038 (MW)
S3S2B	3	2		Base	Yes	–	✔	✔	–	–	–	348	2,820	1320	4140	3000	1176
S3S2H	3	2		High	Yes	–	✔	✔	–	–	–	364	3,300	1680	4560	2600	1176
S3S2L	3	2		Low	Yes	–	–	✔	–	–	–	389	3,000	1600	4080	2520	1176
S3S3B	3	3		Base	Yes	–	✔	✔	–	–	–	371	2,820	1280	4140	2280	1176
S3S2S5B	3	2	5	Base	No	–	✔	✔	–	–	–	348	2,820	1280	4140	2280	1176
S3S2S8B	3	2	8	Base	No	–	✔	✔	–	–	–	348	2,820	1280	4140	2280	1176

Exhibit 8-76: Scenario 3 Base Load Forecast Capacity Additions

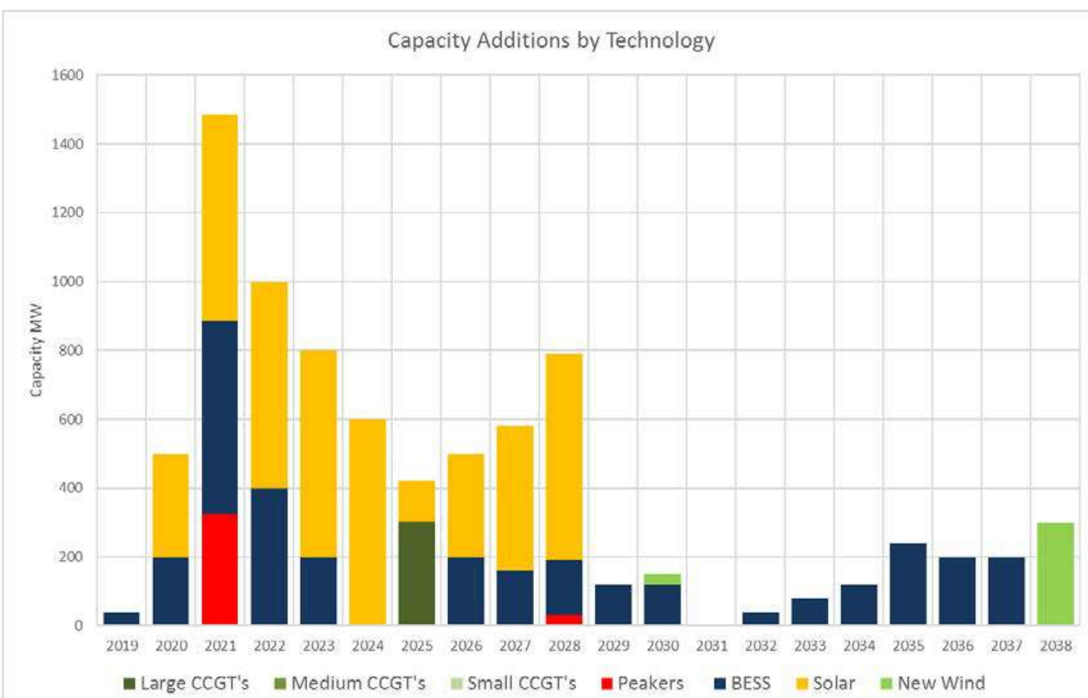
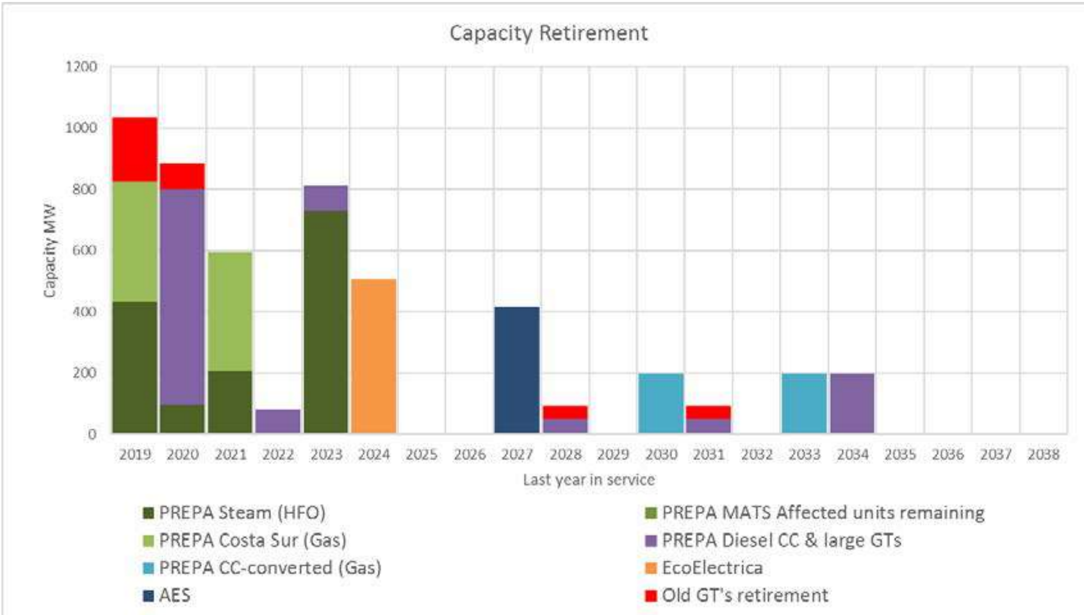


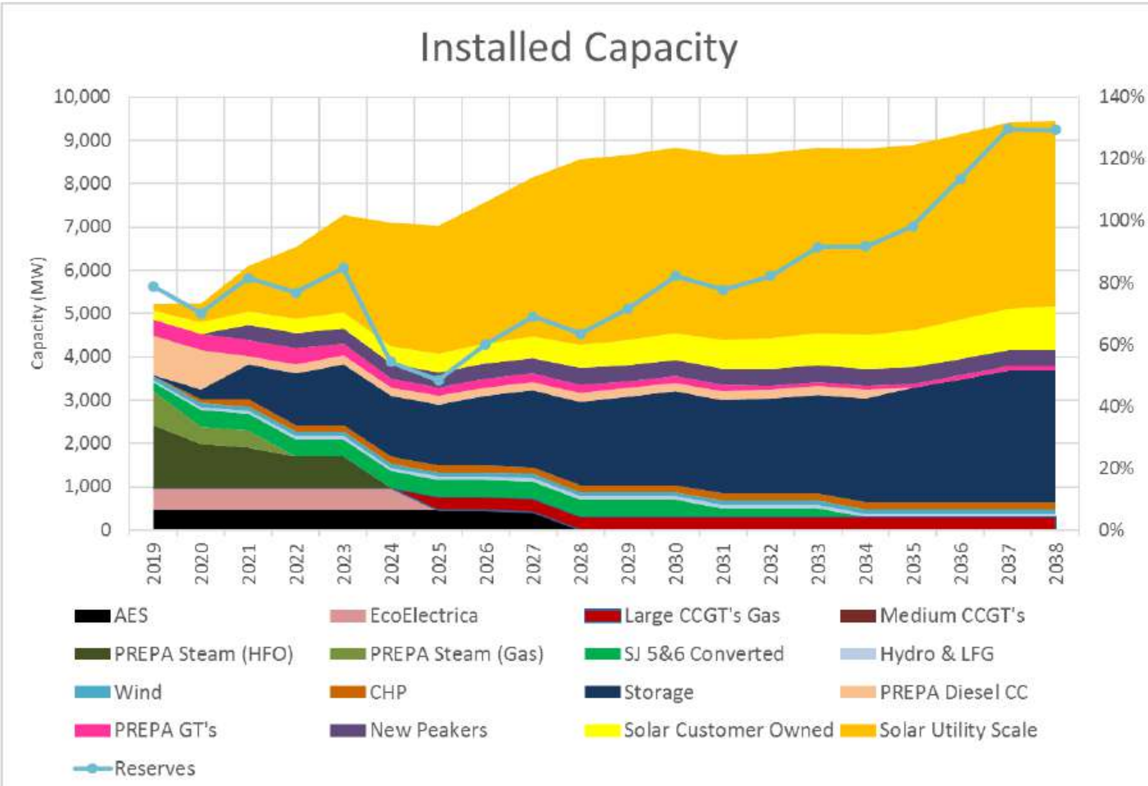
Exhibit 8-77: Scenario 3 Base Load Forecast Capacity Retirements



As PREPA's units and the thermal PPOA's are phased out the operating reserves decline from 79% in 2019 to a low of 48% by 2025, after EcoEléctrica's retirement. Operating reserves rise after 2025 with the storage additions to reach 130% by 2037.

The Planning Reserve Margin of 30% appears not to have been binding constraint on the LTCE plan formulation in this Scenario and observes a minimum of 48% in 2025.

Exhibit 8-78: Scenario 3 Future Capacity Mix

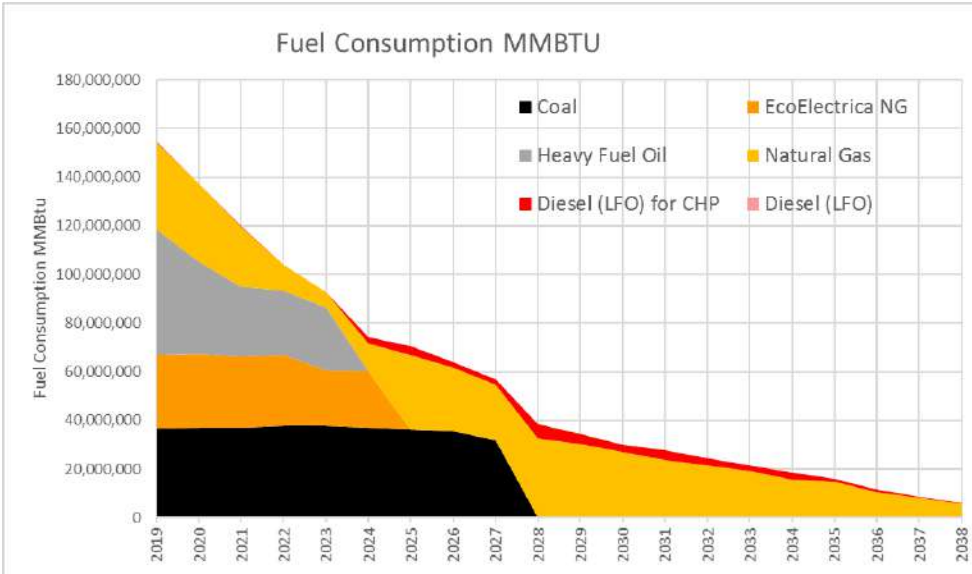


8.5.2 Fuel diversity

In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas along with a sharp drop in overall fuel consumption and associated costs with the implementation of the plan. By 2038, 90% of the installed capacity and 72% of the generation is coming from renewables (90% including Distributed Generation).

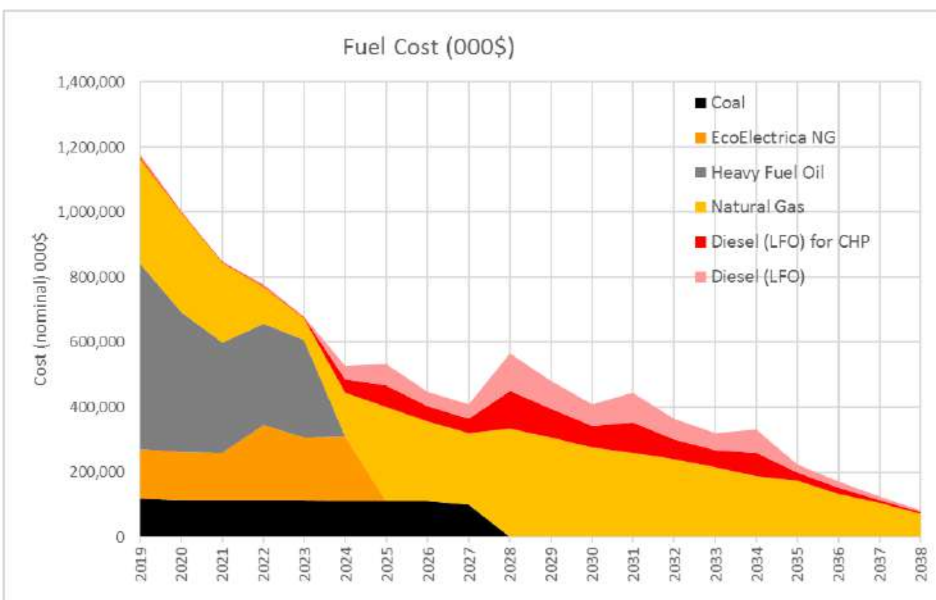
Fuel consumption declines with the retirements of old gas and heavy fuel oil units and peakers along with EcoEléctrica's retirement by the end of 2024. Overall fuel consumption falls significantly over the planning period with total fuel consumption 96% below 2019 levels by 2038, with most of the fuel used coming from natural gas.

Exhibit 8-79: Scenario 3 Fuel Consumption



Fuel costs decline in line with the overall fall in fuel consumption falling to a low of $77.5 million by 2038 (93% below 2019 levels).

Exhibit 8-80: Scenario 3 Fuel Costs

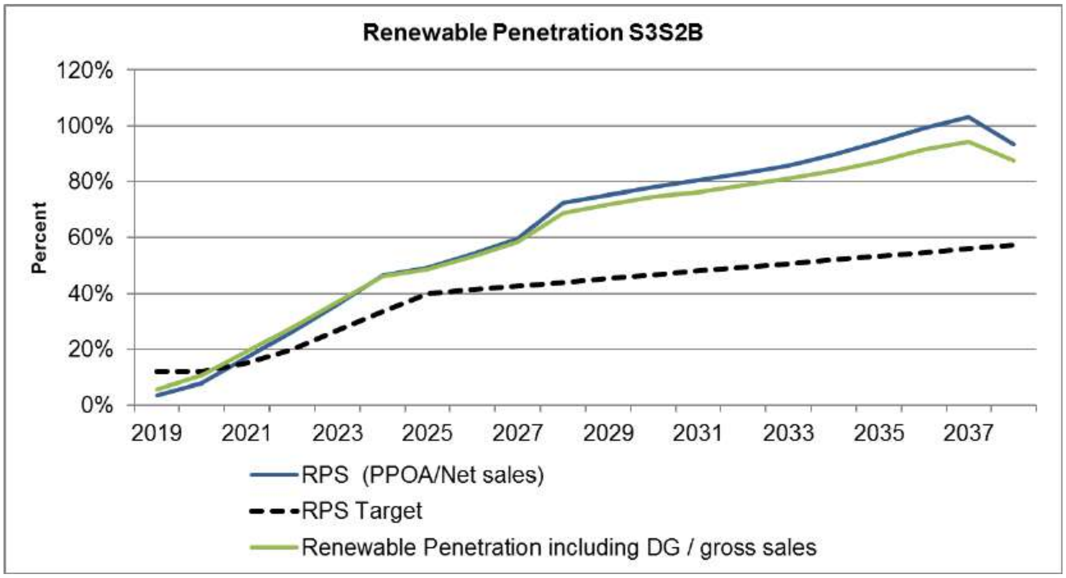


8.5.3 RPS Compliance

The renewable portfolio standard targets of 15% by 2021, 20% by 2022 and 40% by 2025 are all met in the Scenario 3 Plan under all load cases. The levels of renewable penetration exceed a linear trend towards the 60% renewable target by 2040, with the plan reaching 94% by 2037, the highest level of any scenario, as expected.

CO2 emissions reductions decline by 97% compared to 2019 levels under Scenario 3, Strategy 2.

Exhibit 8-81: RPS Compliance Scenario 3



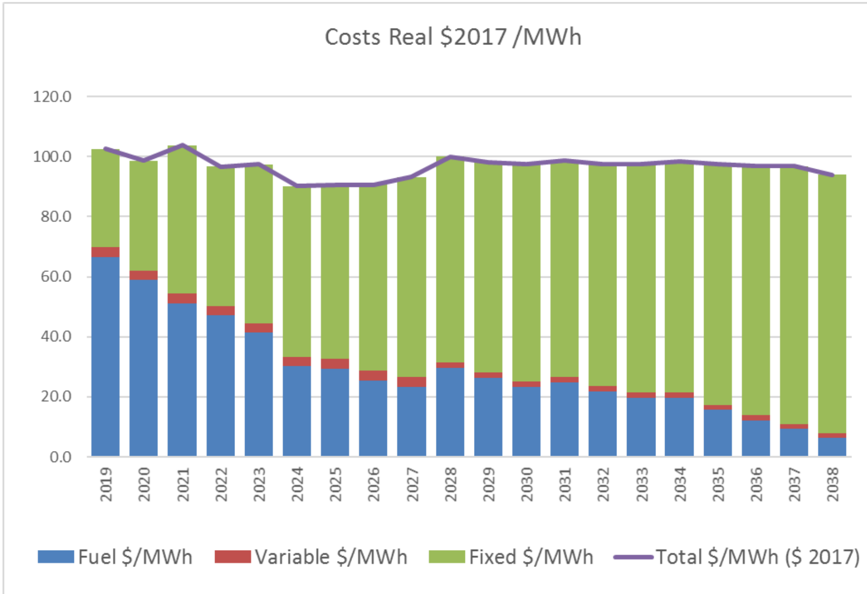
8.5.4 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan from $ 102.5/MWh in 2019 to $89/MWh by 2027 (real $2018), prior to AES Coal retirement. The costs increased in 2028 with the addition of 600 MW of new solar and storage to reach $97/MWh by 2038.

The net present value of all operating costs reaches $13.8 over the study period. This plan is lower in costs than the Scenario 4. Under the high load case, the NPV increase to $15.2 billion and under the low load case to $13.2 billion. Under strategy 3, the NPV of costs is higher at $14.6 billion. Per PREB's order from April 2019, the Siemens run sensitivities around Strategy 2, which shown to be the lowest cost strategy.

The Siemens team run to sensitivities on Scenario 3, including a high gas price sensitivity (sensitivity 5) and a base cost solar sensitivity (sensitivity 8). As shown in Exhibit 8-70, this Plan is more sensitivity to an increase in gas prices than higher capital cost for renewables, despite the large amount of solar installations and nearly 72% of the total generation coming from renewables.

Exhibit 8-82: Scenario 3 Production Costs



Case ID	Scenario	Strategy	Sensitivity	Load	AURORA LTCE	NPV @ 9% 2019-2038 k$	Average 2019-2028 2018$/MWh	NPV Deemed Energy Not Served k$ (1)	NPV + ENS k$	Capital Investment Costs ($ Millions)
S3S2B	3	2		Base	Yes	13,843,500	96.4	205,871	14,049,371	8,474
S3S2H	3	2		High	Yes	15,191,427	97.3	475,629	15,667,056	8,716
S3S2L	3	2		Low	Yes	13,242,760	99.6	303,185	13,545,945	7,851
S3S3B	3	3		Base	Yes	14,627,724	99.8	202,994	14,830,718	8,396
S3S2S5B	3	2	5	Base	No	14,811,928	102.0	205,871	15,017,799	8,474
S3S2S8B	3	2	8	Base	No	14,357,561	99.2	205,871	14,563,432	9,467

8.5.5 Resiliency (Mini Grid Considerations)

In Scenario 3 plan, the critical loads are met by 2021. After 2022, both critical and priority loads are met for most MiniGrid regions.

Siemens estimated the potential costs from unserved energy in the case of a major hurricane impacting the transmission system[76]. It is assumed that a major hurricane occurs every five years impacting major interconnection transmission lines and placing the system into MiniGrids operation for 1 Month, starting in 2022. It is based on a $2000/MWh cost from unserved energy, which considers that the load shedding will be rotated to minimize impact. The $2000 is consistent with the cost of unserved energy for residential customers[77].

[76] This cost is NOT a forecast of future cost, but rather a high-level determination of how the different portfolios resulting from the combination of Scenarios and strategies would perform if every 5 years starting in 2022 a major hurricane impact the island resulting in the operation of the MiniGrids for one month ("Deemed Energy Not Served")

[77] This value is much lower compared to the VOLL determined for PR, in the range of $30,000/MWh

Exhibit 8-22 summarizes the economic costs by MiniGrid region for Scenario 3. There are potential costs for San Juan-Bayamon and Caguas and to a lesser extend in Mayagüez North. Overall, there is an incremental 80 million in potential costs from unserved energy in the case of a major hurricane impacting the island under this plan. This is much lower compared to $228 million for Scenario 4.

Exhibit 8-83: NPV Cost of Energy Not Served by MiniGrids ($000)

MiniGrid	Scenario 3	Scenario 4
San Juan-Bayamon	$ 23,869	$ -
Ponce	$ -	$ -
Carolina	$ 73,980	$ 73,980
Caguas	$ 73,848	$ 87,124
Arecibo	$ 34,031	$ 79,405
Mayaguez-North	$ -	$ -
Mayaguez-South	$ 143	$ 143
Cayey	$ -	$ 6,792
Total	$ 205,871	$ 247,445

8.5.6 Nodal Analysis Scenario 3, Strategy 2

The Siemens team evaluated the least cost plan under Scenario 3 using a nodal simulation. The objective is to identify the effects of transmission on the key metrics of congestion, technical losses, production costs, renewable curtailment and energy not served.

The results of the nodal runs show that in the first 10 years (2019 – 2028) the production costs of the nodal runs match very closely with those of the zonal runs used for the LTCE assessment (see Exhibit 8-32). The transmission technical losses, that were not considered in the zonal runs, but are assessed in the nodal are fairly low starting from about 1.1% and dropping to 0.5% by 2028.

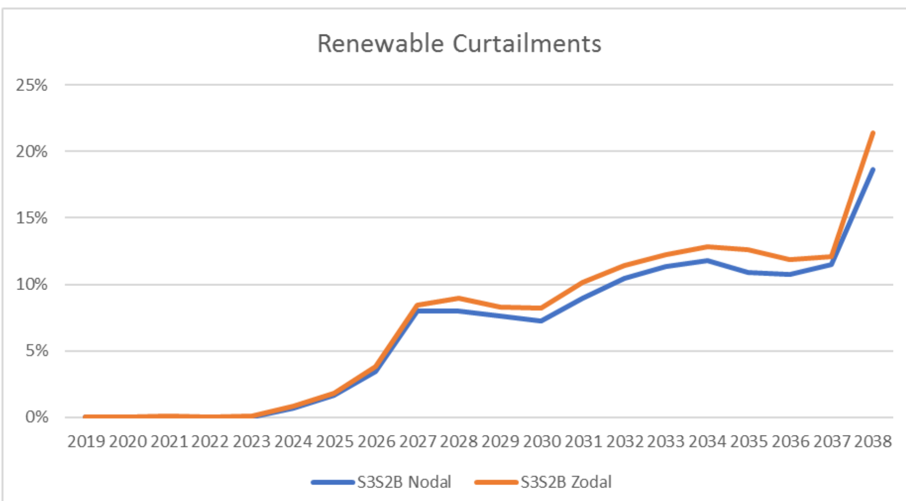
The amount of curtailment observed for the new solar generation was lower in the Nodal runs as shown in Exhibit 8-78, which confirms that transmission is not expected to create curtailment.

There was no energy not served in the nodal runs, which is in line with the results of the zonal runs.

In summary the minimal impact of transmission was expected due to the greater distribution of generation resources and reduced load.

Exhibit 8-84: Production Costs Nodal vs. Zonal and Renewable Curtailment

Exhibit 8-85: Renewable curtailment



8.6 Scenario 5 Base Case Results

Scenario 5 is a case requested by the Energy Bureau to evaluate how the capacity expansion would look with minimal restrictions. For this Scenario, in addition to the LNG terminal considered in Scenario 4, the Aguirre Offshore Gas Port (AOGP) is assumed to achieve full permitting and regulatory approval and can move forward. In line with the minimal restriction approach, the Scenario reflects a traditional and centralized energy program that emphasizes economic and reliability on a system integrated basis (Strategy 1) without minimum generation requirements to meet peak demand on a regional basis.

Other assumptions in the simulation of this Scenario includes gas to Yabucoa (east) and Mayagüez (west) through ship-based LNG, as well as gas to the north through land-based LNG at San Juan. The Scenario uses the base case assumption of solar and storage costs and availability. In addition, a larger combined cycle (H-class) could be built in this Scenario.

The generation portfolio identified as Scenario 5 Strategy 1 result in a plan that has lower production costs as compared to Scenario 4, about $227.5 million below. However, the potential costs reductions could be fully offset if the transmission network is impacted by a major hurricane placing the system into MiniGrid operations (the system is segmented in areas). A high-level estimate of the impact shows a $593 million of potential costs from energy not served during a month while the transmission system is repaired.

8.6.1 Capacity Additions and Retirements

The economic simulation of the Scenario 5 results in 2,580 MW of utility scale PV additions over the study period, 300 MW below Scenario 4 plan. All of the capacity is installed through 2025 to meet RPS targets.

In this Scenario, 1,480 MW of battery energy storage is built over the study period, mostly through 2025 in order to support the solar installations.

Two large H-Class CCGTs are installed in Costa Sur (Ponce west minigrid), one in 2025 and the other in 2028 (369 MW each). No other CCGTs are installed in Bayamon, Mayaguez or Arecibo. The peaking needs in this case is similar to Scenario 4 portfolio with 317 MW of new peakers through 2025.

San Juan 5 and 6 are retired both economically in 2026 and 2031 after being converted to natural gas in 2019, with one of the units suggested to stay online to provide reserves in the San Juan-Bayamon area, in particular in the case of a major Hurricane hitting the island. EcoEléctrica is retired economically in 2024, in line Scenario 4 and AES retires by the end of 2027, by model input.

The plan is MATS compliant after 2024 and achieve 67% RPS compliance by 2038, above the 60% RPS mandate by 2040.

Exhibit 8-86: Scenario 5 Portfolio Capacity Additions

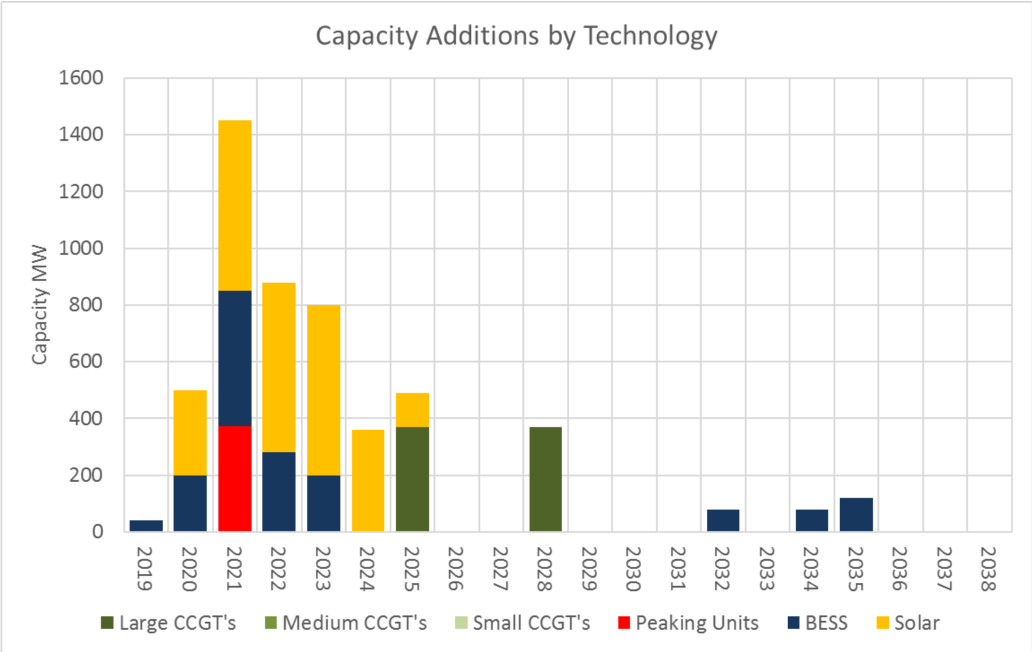
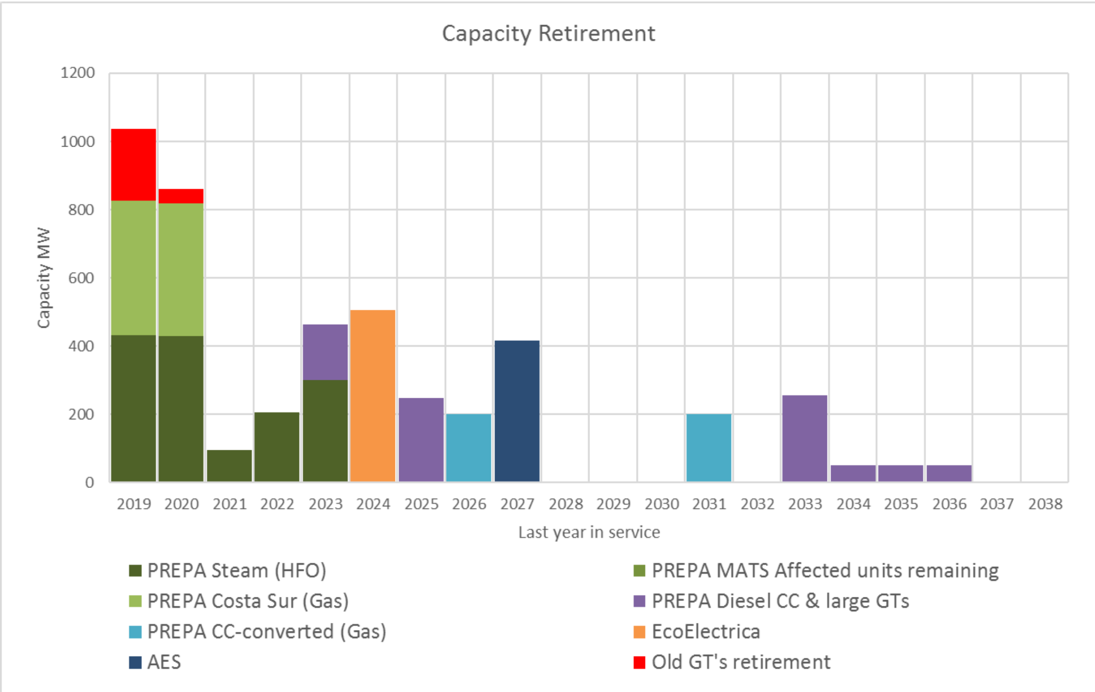
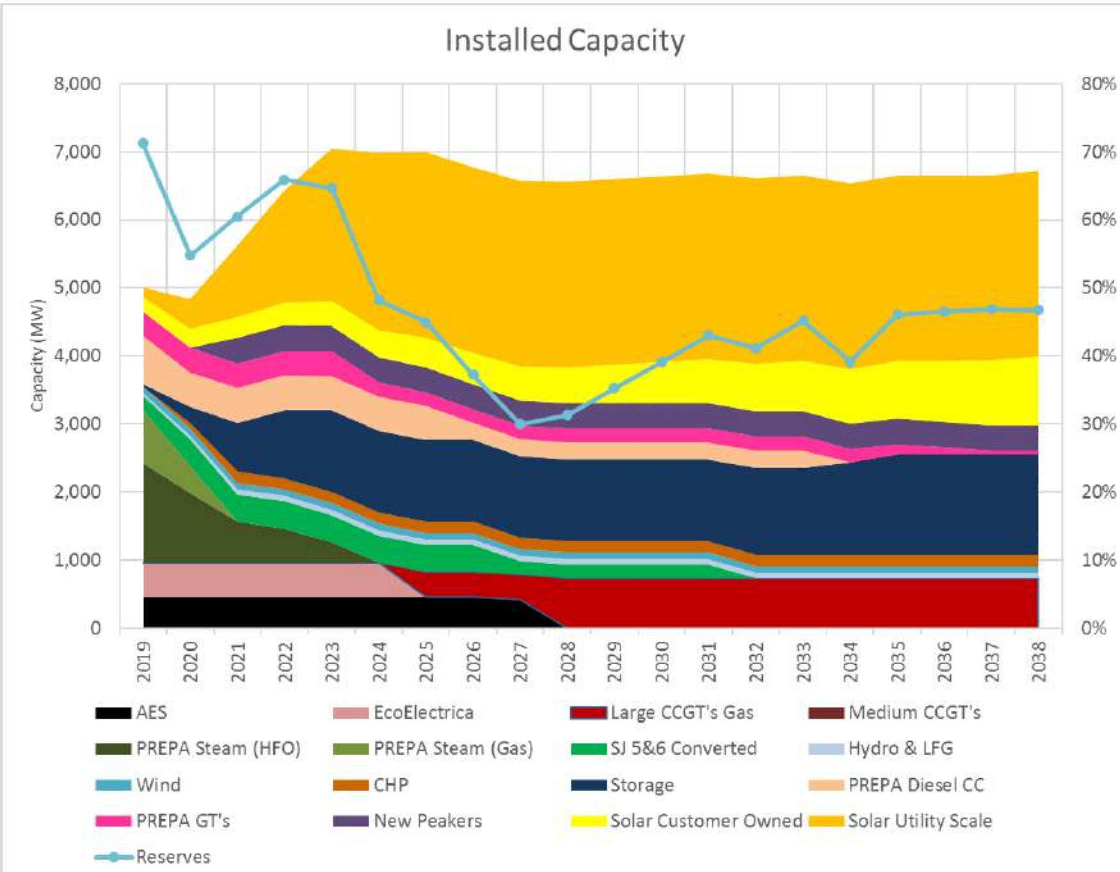


Exhibit 8-87: Scenario 5 Portfolio Capacity Retirements



As PREPA's units and the thermal PPOA's are phased out the operating reserves decline from 70% in 2019 to a low of 30% by 2027 with the retirement of AES. The Planning Reserve Margin of 30% appears to have a binding constraint on the LTCE plan formulation in this Scenario with reserve margins for the system falling near this threshold in 2027-2028.

Exhibit 8-88: Scenario 5 Capacity Mix



8.6.2 Fuel Diversity

In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas along with a sharp drop in overall fuel consumption and associated costs with the implementation of the plan. Fuel consumption declines with the retirements of old gas and heavy fuel oil units and peakers along with EcoEléctrica's retirement by the end of 2024. Total fuel consumption drops 83% by 2038 with all of the fuel used coming from natural gas.

Fuel costs decline in line with the overall fall in fuel consumption falling to a low of $209.5 million by 2038 (82% below 2019 levels) with all the retirements, including AES.

Exhibit 8-89: Scenario 5 Fuel Mix

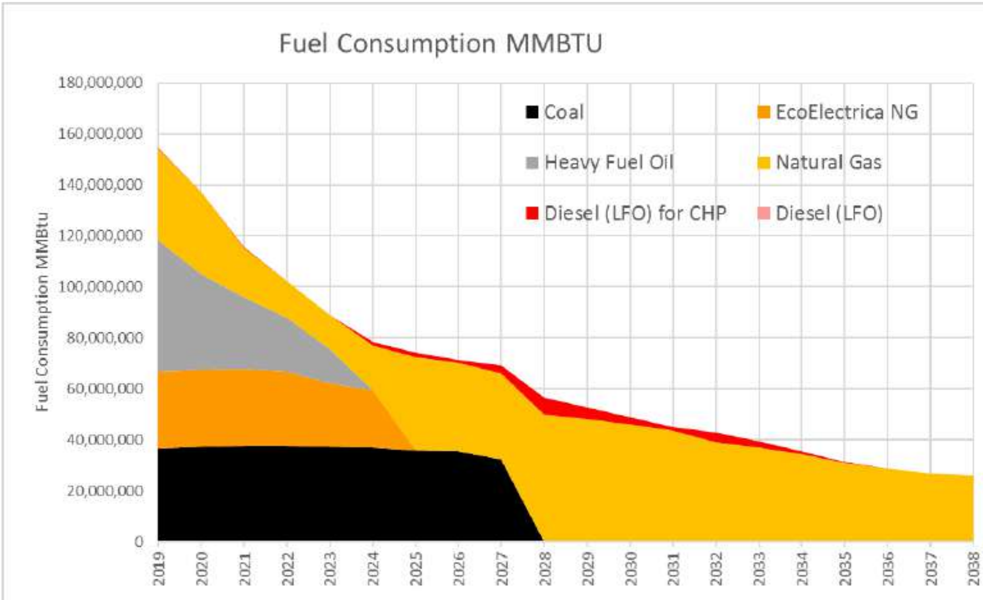
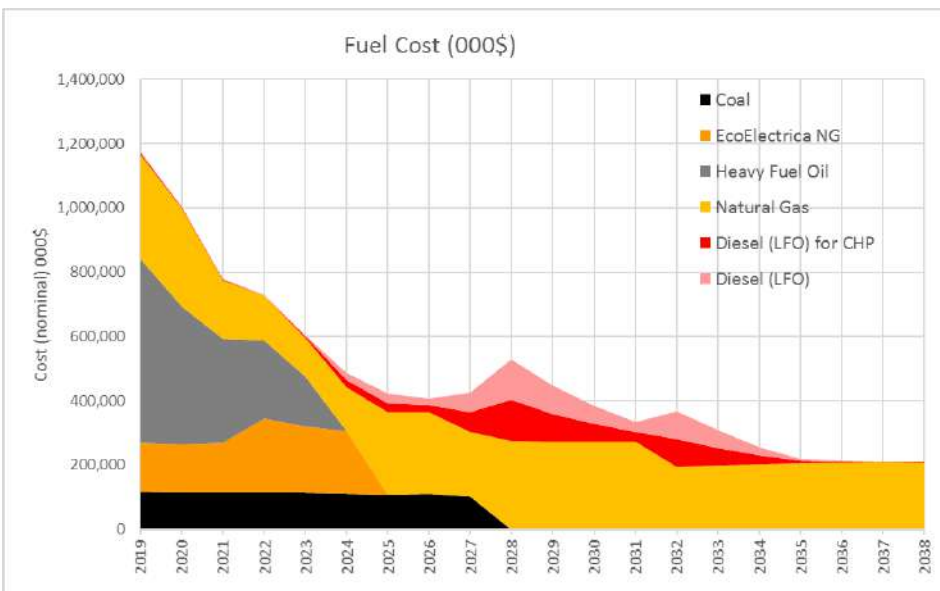


Exhibit 8-90: Scenario 5 Fuel Costs

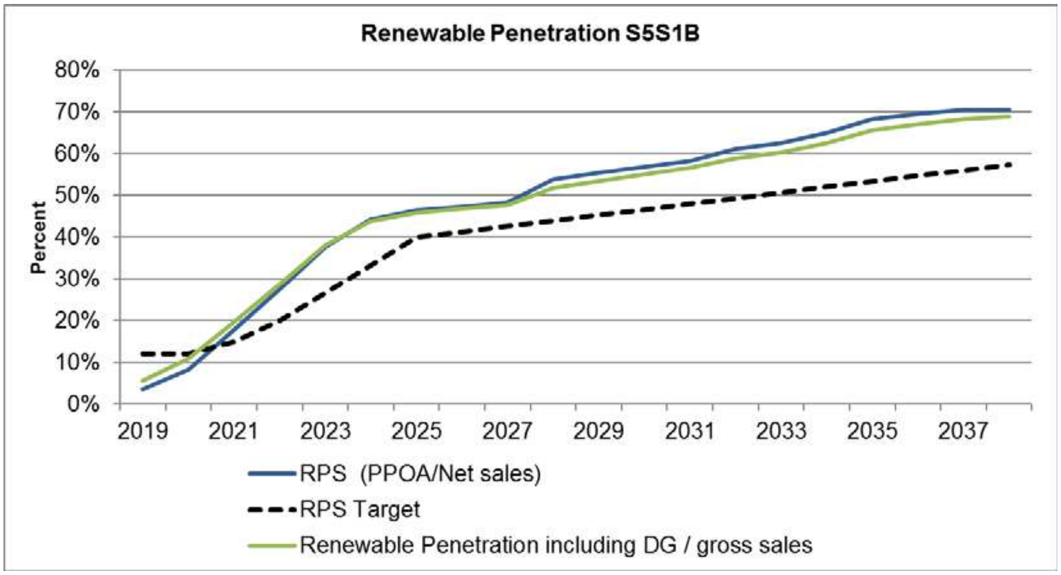


8.6.3 RPS Compliance

The renewable portfolio standard targets of 15% by 2021, 20% by 2022 and 40% by 2025 are all met in the Scenario 5 Plan. The Plan achieves 67% RPS compliance by 2038, above the 60% RPS mandate by 2040.

CO2 emissions decline by 87% compared to 2019 levels under Scenario 5.

Exhibit 8-91: Scenario 5 RPS Compliance



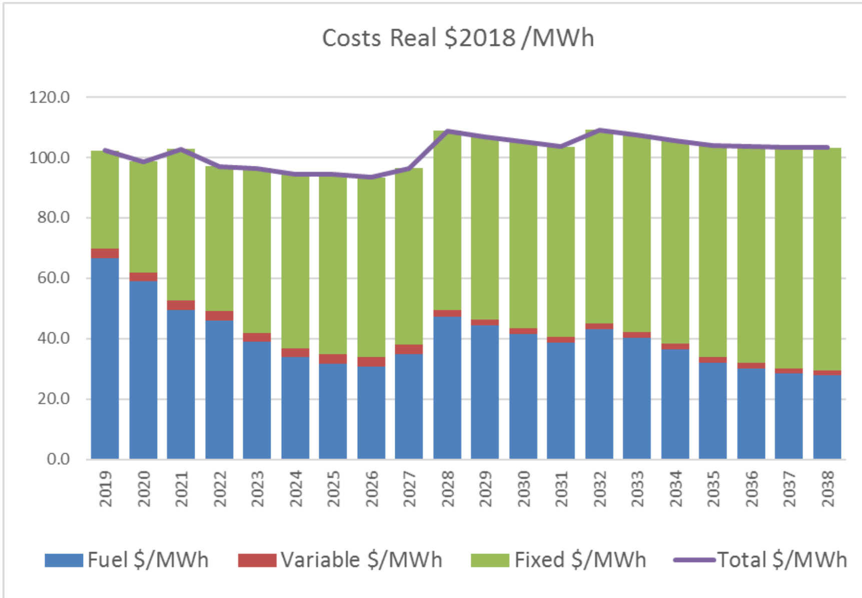
8.6.4 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan from $102/MWh in 2019 to $93/MWh by 2026 (real $2018), prior to AES Coal retirement, with the addition of solar and storage and the retirement of older generation. The costs increased in 2028 with AES retirement and the addition of a new CCGT in Costa Sur to $108.8/MWh. System costs fall in the last 10 years primarily due to falling fuel costs to reach $103.2/MWh by 2038.

The net present value of all operating costs reaches $14.1 billion over the study period. The Plan costs is % lower compared to Scenario 4.

The Siemens team run three sensitivities around high gas prices and high and low capital costs for renewables. As with other scenarios, the Plan is more sensitivity to changes in fuel prices compared to changes in capital costs for renewables. With higher gas prices, the NPV of costs rise to $15.6 billion compared to $15.3 with higher costs of renewables. In contrast, lower costs for renewables would reduce the cost of the Plan to $13.8 billion.

Exhibit 8-92: Scenario 5 System Costs



Case ID	Scenario	Strategy	Sensitivity	Load	AURORA LTCE	NPV @ 9% 2019-2038 k$	Average 2019-2028 2018$/MWh	NPV Deemed Energy Not Served k$ (1)	NPV + ENS k$	Capital Investment Costs ($ Millions)
S5S1B	5	1		Base	Yes	14,122,690	98.4	593,173	14,715,863	6,201
S5S1S5B	5	1	5	Base	No	15,660,368	110.0	593,173	16,253,541	6,201
S5S1S1B	5	1	1	Base	No	13,813,169	96.4	593,173	14,406,342	5,697
S5S1S6B	5	1	6	Base	No	15,335,600	106.4	593,173	15,928,773	8,165

8.6.5 Resiliency (Mini Grid Considerations)

In Scenario 5 plan, the critical loads are not met with thermal resources on most MiniGrids, are not met with local generation while the plan is being developed in 2019 through 2022. After 2022, both loads are met for most MiniGrid regions.

Siemens estimated the potential costs from unserved energy in the case of a major hurricane impacting the transmission system[78]. It is assumed that a major hurricane occurs every five years impacting major interconnection transmission lines and placing the system into MiniGrids operation for 1 Month, starting in 2022. It is based on a $2000/MWh cost from

[78] This cost is NOT a forecast of future cost, but rather a high-level determination of how the different portfolios resulting from the combination of Scenarios and strategies would perform if every 5 years starting in 2022 a major hurricane impact the island resulting in the operation of the MiniGrids for one month ("Deemed Energy Not Served")

unserved energy, which considers that the load shedding will be rotated to minimize impact. The $2000 is consistent with the cost of unserved energy for residential customers[79].

Exhibit 8-79 summarizes the economic costs by MiniGrid region for Scenario 5. There are potential costs for most regions, in particular San Juan-Bayamon, Carolina and Caguas showing the latest potential impact and costs. Total costs for the system are north of $593 million, $345.7 million higher than Scenario 4, basically illustrating the risks to the system of going into a centralized system.

Exhibit 8-93: Cost of Energy Not Served by MiniGrids (NPV Costs $000)

MiniGrid	Scenario 5	S4S2B
San Juan-Bayamon	$ 438,520	$ -
Ponce	$ -	$ -
Carolina	$ 60,948	$ 73,980
Caguas	$ 65,622	$ 87,124
Arecibo	$ 12,546	$ 79,405
Mayaguez-North	$ -	$ -
Mayaguez-South	$ 8,746	$ 143
Cayey	$ 6,792	$ 6,792
Total	$ 593,173	$ 247,445

8.6.6 Nodal Analysis Scenario 5, Strategy 1

The Siemens team evaluated the least cost plan under Scenario 3 using a nodal simulation. The objective is to identify the effects of transmission on the key metrics of congestion, technical losses, production costs, renewable curtailment and energy not served.

The results of the nodal runs show that through the planning period, the production costs of the nodal runs match very closely with those of the zonal runs used for the LTCE assessment (see Exhibit 8-77). The transmission technical losses, that were not considered in the zonal runs, but are assessed in the nodal are fairly low starting from about 1.1% and dropping to 0.7% by 2038 as consequence of the reduced load and greater distribution of the generation.

The amount of curtailment observed for the new solar generation was lower in the Nodal runs as shown in Exhibit 8-78, which confirms that transmission is not expected to create curtailment.

There was no energy not served in the nodal runs, which is in line with the results of the zonal runs.

[79] This value is much lower compared to the VOLL determined for PR, in the range of $30,000/MWh

In summary the minimal impact of transmission was expected due to the greater distribution of generation resources and reduced load.

Exhibit 8-94: Production Costs Nodal vs. Zonal and Renewable Curtailment

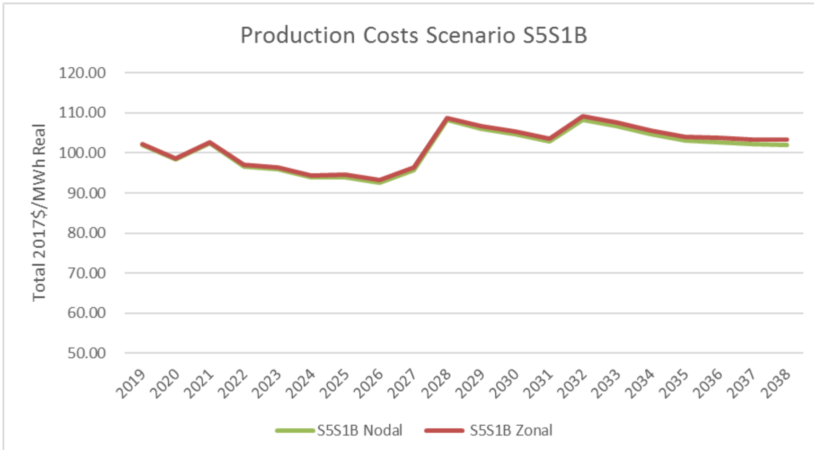
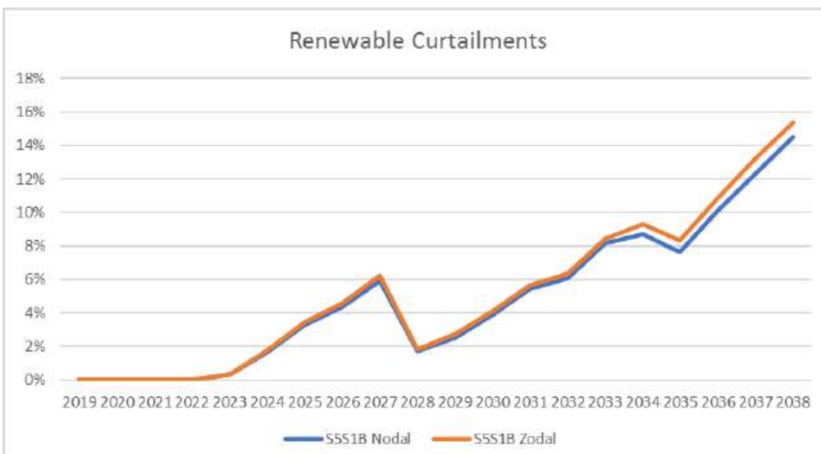


Exhibit 8-95: Transmission Losses Nodal Simulation



8.7 Planning Reserve Margin Considerations

8.7.1 Introduction

The purpose of this subsection is to discuss Planning Reserve Margin (PRM) in more depth.

As was illustrated above the adopted PRM of 30% was found not to be binding under most conditions and in particular for the plans that are considered to contain the recommended decisions; Scenario 4 Strategy 2 with modifications and the ESM plan. However, in this

section we review those conditions in which PRM was binding and resulted in new builds. In addition, we provide indication of values to which this PRM could be lowered in the future.

The PRM of 30% was found to be adequate on earlier resource sufficiency assessments ant it is roughly equal to twice the largest units in the system (2x450 MW) divided by an historic load of 3,000 MW. The objective was to start with this value as an approximation and if it became an important binding element in our assessment, then we would reduce it until the planning criteria of four LOLH per year was exceeded. However, this was seldom the case and in this section we investigate this further.

To identify Scenarios where PRM was binding, the reserve margin for all Scenarios and cases was investigated for all years. For cases where the reserves level was close to 30% (PRM) we evaluated if new peaker units were built in response to the low reserve levels. It should be noted here that for the preferred portfolios, S4S2B and ESM, PRM was never a binding constraint, i.e. it did not explicitly trigger new peaker units builds. The cases where PRM was a binding constraint are discussed below (this corresponds to the prior filing but illustrate the point).

8.7.2 Binding Planning Reserve Margin Cases

Among all the available portfolios, the following cases were found to have binding PRM conditions, which resulted in new builds.

8.7.2.1 S3S3B

In this portfolio, the PRM level dropped to 31.6% in 2024, taking into consideration demand response with a value of 2.6% of peak demand. This drop can be explained due to the retirement of steam (HFO) and diesel CCGT units; a total of 606 MW. In 2025, EcoEléctrica (507 MW) is retired and two (2) new large CCGT gas units (604 MW) were added. In addition, two (2) reciprocating diesel units, 16 MW each, were added in 2025. Because of these additions, the PRM level increased to 39.6% in 2025 (including a demand response of 2.8% of peak demand). It is possible that the peakers were triggered by the reduction in reserves, however most of the additions are economic, as in 2025 new CCGT's can come online.

As indicated earlier, Scenario 3 is a low cost Scenario, as compared with Scenario 4, but it contains levels of renewable generation that will be hard to integrate and assumes deeper reduction on renewable. Hence the entry or not of the peakers above did not change the opinion on this case.

8.7.2.2 S3S3H

In this portfolio, the PRM level was reported as 32.9% in 2026, including a demand response of 2.9% of peak demand. In 2027 and 2028 AES units (454 MW) were retired and one (1) new large CCGT gas unit (302 MW) was added. In addition, ten (10) peaker units with a total of 213 MW were added in the years 2027 and 2028, bringing the PRM to 43.7% in 2028 (including a demand response of 3.1% of peak demand). Again, the PRM could have been binding, but the addition of the CCGT is triggered by economics and retirement of AES.

As indicated earlier Scenario 3 is a low cost Scenario, as compared with Scenario 4, but it contains levels of renewable generation that will be hard to integrate and assumes deeper reduction on renewable. Hence the entry or not of the peakers above did not change the opinion on this case.

8.7.2.3 S4S3B

In the existing S4S3B portfolio, from year 2025 into year 2028 there was a total of 1160 MW of thermal generation retirements at San Juan 6 CC, AES 1&2, and diesel CCGT units, while one (1) new large CCGT gas unit (302 MW) was added. In addition, four (4) peaker units with a total of 115 MW were added in the years 2026 to 2028, bringing the PRM to 31.1% in 2028 (including a demand response of 3.1% of peak demand). In this case the PRM was biding and was investigated further as described below.

8.7.2.4 S4S1B

In this portfolio, in year 2032 there was a total of 514 MW of thermal generation retirements at PREPA's existing diesel CCGT and GT units. The only thermal new units added in 2032 was a 16 MW diesel reciprocal unit, which brings the PRM to 33.2% in 2032, including a demand response of 3.5% of peak demand. The effect is marginal and towards the end of the period. Also, strategy 1 does not provides adequate levels of local reserves for resiliency.

8.7.2.5 S5S1B

In the existing S5S1B portfolio, in 2027 AES was retired and new generation was added. capacity of 38 MW at AES units, in addition to adding two (2) diesel reciprocating engines with a total capacity of 32 MW. As a result, PRM was reported as 33.6% in 2027, including a demand response of 3.0% of peak demand.

8.7.3 Planning Reserve Margin Sensitivity Analysis

PRM was a binding constraint and triggered new peaker unit additions in limited cases. For most of the years PRM was not binding despite of the relatively low reserve levels for reasons discussed in the previous subsection. To examine the impact of reductions in the PRM, the same portfolio discussed above, S4S3B was assessed for the year 2028 with reduced levels of reserves, as discussed below:

1. Control Case: this case represents the original conditions in portfolio S4S3B, i.e. no changes made. As mentioned previously, the PRM level is 31.1% (including 3.1% of demand response) and without any unserved load reported.

2. The new peaking units built in 2027 and 2028 were removed 115 MW. The units include:

    a. Two (2) Aero LM6000 units: each unit has a capacity of 39 MW and they were added in 2027 and 2028.
    b. One (1) Aero GE LM2500 unit: this peaker unit has a capacity of 21 MW and was built in 2027.
    c. One (1) RICE: this unit has a capacity of 16 MW and was built in 2028.

    Because of not building these four peaking units, the PRM level dropped to 26.9%. However, no unserved load was reported. Hence in principle a 27% PRM could have been selected and he units above possibly may not have been built.

3. In addition to not including the generation above, the Cambalache CT2 and CT3 were retired earlier (165 MW) in 2028. As a result, the PRM level dropped to 23.2%, and an unserved load of 102 MWh over 8 hours was reported. The total reported savings for this case is estimated to be $31.3 million, while the unserved energy cost is $3.1

million. However, PREPA's planning limit of 4 loss of load hours (LOLH) is exceeded. It should be noted that for this case, all the unserved load is reported in Carolina Area. Based on the above a PRM of 23% would be aggressive.

4. In this final test two (2) peaker GTs (100 MW) at Mayagüez were also removed. The reserve dropped under 20% and there was 3621 MWh of unserved load over 123 hours. Not only the unserved duration greatly exceeds the 8 hour limit, but also the unserved load cost ($109 million) exceeds the potential savings ($35.3 million). For this case, the entire unserved load is reported in Carolina and Bayamon Areas (mostly in Carolina).

Siemens is of the opinion that the PRM of 30% was adequate for this study, however, it was desired to investigate the impact of lower PRM in the LTCE optimal calculations to identify conditions in which PRM becomes a binding constraint. Therefore, analysis was conducted again for portfolio S4S3B with a PRM target value of 20%.

The LTCE resulting from this optimization had in fact higher levels of reserves reported compared to previous solutions in which the PRM target was set to 30%. This increase in reserve levels despite using lower PRM target is mainly caused by the optimization algorithm that was able to find an slightly better solution in which the PRM again is not a binding constraint and confirmed that it had minimal impact on the overall results. Further review of this run identified that in the years 2026 to 2030 there was a net capacity increase of 197 MW, which resulted in increasing the PRM level from 44% to 54%. On the other hand, in the years 2030 to 2032 there was a net capacity reduction of 477 MW in the form of retirements, which resulted in reducing the PRM level from 54% to 30%.

Based on the sensitivity analysis results presented above, it can be concluded that PRM does not have a noticeable impact on the overall solution even when PRM target is reduced to relatively low values, e.g. 20%. The higher reserve levels and lower overall total cost, which were achieved with the 20% PRM target imply that PRM was not a binding constraint and did not trigger new builds.

Part
9

Caveats and Limitations

As was explained before in this report, the 2019 IRP is not a classical IRP designed to identify the least cost approach to address the expected gap between load and resources and maintaining a desired Planning Reserve Margin (PRM), but rather produce a plan that satisfies the objectives of providing a service that is customer centric, financially viable, is reliable and resilient, and promotes economic growth. These objectives are to be satisfied on a context of significant declines in the load and of PREPA's current fiscal situation as a debtor under the Title III of the PROMESA Act, which requires PREPA to follow a path to comply with healthy financial utility practices. In addition, the devastation to Puerto Rico's electrical infrastructure from the 2017 Hurricanes forced PREPA to rethink its entire system design, including resources planning addressing the following:

- Existing aging generation infrastructure that burns mostly heavy fuel oil, has poor reliability, does not meet all environmental regulations (e.g. MATS), and is inflexible, which limits the incorporation of renewable resources.
- Current and forecasted industry trends showing a reduction in the cost of renewable resources, especially solar photovoltaic (PV) and bulk battery storage.
- Achieve compliance with the Renewable Portfolio Standard (RPS) mandate.
- Shift from centralized generation located in the south of the island to a more decentralized generation mix, particularly for achieving a more resilient electric service.

Taking in consideration the above, through input received during a series of Stakeholder Workshops, discussion with PREPA staff, and Siemens own knowledge and experience with resource planning, the PREPA and Siemens project team defined a number of aspects that the resource planning resulting from this IRP must address. These aspects are contained in the definition of the Strategies, Scenarios and Sensitivities presented in this IRP. The development of these strategies, scenarios and sensitivities required the formulation of assumptions and forecasts, which are also presented in this report.

It is noted that the modeling done as part of this IRP was performed following electric industry standards and using industry accepted resource planning tools, like AURORAxmp. However, the IRP analyses considered a large number of options and uncertainties, taking into consideration formal and informal input from both PREPA and a large number of stakeholders. The inputs used for these analyses, simulations and modeling were based on the aforementioned assumptions and forecasts. Hence, the modeling results will be valid while the assumptions are achieved, and the forecasts are fulfilled.

Considering the conditions mentioned above, there are a series of main caveats and limitations of the IRP, which are summarized in this part. Following, we present a list of these key caveats and limitations:

1. The IRP evaluates the highest public good and the protection of the interests of the residents of Puerto Rico, which may not necessarily be identical to the interests of PREPA if viewed from a narrow utility perspective.

2. The IRP does not directly address specific asset technology, asset optimization, fuel optimization, procurement, interconnection issues, new contracts, contract re-negotiation, collective bargaining rights, site specifics, or ownership.

3. The IRP does not set rate structures.

4. The IRP does not directly address the debt restructuring process or privatization plans.

5. The implementation of the Puerto Rico Electric System Transformation Act is a separate process outside the accelerated timeline of developing the IRP.

6. The IRP was conducted with extensive inputs from a broad group of stakeholders including the public, the customers, under an accelerated timeline and in parallel with many other related activities but may not consider or fully consider all externalities that are critical for the Preferred Resource Plan implementation or execution.

7. From the Stakeholder Workshops, it was found that stakeholders generally preferred a strategy founded on distributed (Strategy 2) rather than centralized (Strategy 1) supply resources for Puerto Rico's situation because it provides a more resilient grid, as the supply is located closer to the load. Participants viewed Strategy 3 (combination of centralized and distributed generation) as a short- or medium-term step to Strategy 2. Following the preferences of the stakeholders, the IRP analyses focused on Strategies 2 and 3 and only one case was run with Strategy 1. It is noted that the larger centralized resources aligned with Strategy 1 usually provide lower costs of energy than distributed resources but depend on the reliability of the transmission system during a major event like a hurricane. Considering the experience with the 2017 hurricanes in Puerto Rico, a distributed resources strategy was selected for providing resiliency to the electric service, even though it could result in higher costs.

8. The load served by PREPA is expected to significantly decline over the IRP's planning horizon due to a combination of expected base load reduction (driven by population and economic changes), energy efficiency gains, and demand side resources. Even though the modeling was performed considering three load forecast levels (High, Base and Low) and the Preferred Resource Plan is expected to work well in all of them by preserving the flexibility to adapt. However, a drastic change in these assumptions could affect the IRP results and require significant changes in such plan. Hence, it is important to review the IRP plan in the term of three years stated by Act 57-2014 for verifying these assumptions.

9. The main sources of data used for the load forecast included Moody's Analytics, the International Monetary Fund, World Bank, the U.S. Census Bureau, Federal Reserve

of Economic Data of St. Louis (FRED), and Puerto Rico's Federal Management Oversight Board (FOMB). In particular, Siemens used FOMB historical and forecasted data for GNP and population for the IRP load forecast. Siemens assumed that the data from these sources is reliable and correct. If, in the future, it is found that this data or any part of it is incorrect, a revision of the load forecast, and the IRP modeling shall be done for correcting the IRP results.

10. The environmental regulations determined by Siemens and PREPA to be potentially significant and factored into the IRP analysis include federal air regulations, water regulations, and local policy dictating targets for renewable and alternative energy. . A significant change in these assumptions could affect the IRP results and require changes in such plan. Therefore, it is important to review the IRP plan in the term of three years stated by Act 57-2014 for verifying these assumptions.

11. The conventional generation technologies (CCGTs, GTs, RICE, etc.) included in the IRP are considered representative and selected for modeling purposes. There are multiple developers that can provide equivalent equipment and the findings in the IRP should not be considered prescriptive of a particular generation design. This technologies selection was the result of Siemens screening of available new generation resources that allow for system flexibility and reliability, including the integration of large blocks of renewable capacity, primarily solar.

12. The location of the peaking generation is a function of the needs for local support, which in turn are a function of the available generation and load. If there are changes with respect of the assumptions in this document, PREPA should have the flexibility to adjust and redeploy these units.

13. The IRP considers that all new renewable generation will have market prices adjusted to Puerto Rico conditions. This implies that all the pre-existing contracts associated with projects that have not started construction, are voided and new fully competitive RFP processes are advanced. For the projects in operation or pre-operation, Siemens assumed fixed price conditions based on current contracts prices. If these marked prices for new generation are not achieved, the LTCE plans are directly affected, probably resulting in much lower integration of renewables with the system.

14. The IRP assumes an accelerated timeline for solar and storage projects, assuming fast track of permitting, proper submittal of project design for evaluation by PREPA, and securing the land for the interconnection line and facilities. In addition to unforeseen events that could delay these tasks, this timeline could be delayed by limitations on the amount of annual installations that can effectively be carried out in parallel maintaining the continuous operation of the power system.

15. In the case of utility scale storage, it is noted that the amount recommended in the IRP is much higher than the total capacity currently installed in the whole United States. This represents an installation never done before in a power grid, especially nor in an isolated system like the one in Puerto Rico. Hence, it is foreseen that the first storage projects will take more time to be developed and integrated with the power system, as they will be the pilot projects of very large bulk storage in Puerto Rico and the main land. Particularly, the learning curve will be defined with those projects that have to be developed maintaining the reliability and continuity of the service in Puerto Rico.

16. For maintaining the reliability of the system, PREPA should not commission neither allow the interconnection of PV solar or wind projects to the grid until the required corresponding energy storage component be commissioned and interconnected in full compliance with the energy storage technical requirements. The solar PV projects shall still comply with the MTRs related with frequency ride through, voltage ride through, reactive power capability and voltage regulation in addition to their full compliance with the frequency regulation and frequency response requirements to be met by either separate or integrated energy storage. This approach is expected to foster competition and innovation while at the same time ensuring that the required regulation and energy shifting will be available for the PV integration before its interconnection.

17. The IRP recommends the retirement of the existing steam generating fleet at different times, including the Aguirre 1 & 2 units in 2019. However, these recommendations are based on other prerequisite developments which include the forecasted reduction in load, assumed levels of reliability of the remaining of the existing fleet at the time of retirement, and the commissioning of the new generation resources. The IRP commissioning dates formulated last year, are likely to slip and it is not unrealistic to expect the planned unit retirements presented in this document to be correspondingly postponed. Moreover, the retirement of existing generating units should be only implemented after all the prerequisites above have been met, particularly that all new resources are fully operational, and units planned for retirement are not required for reliable operation of the system.

18. The IRP is based on certain assumptions with respect of expected technical performance and capital cost estimates for generation resources including thermal resources and LNG terminal, that while considered reasonable, could have an important impact on implementation if material deviations occurred. Most of the recommended projects are at very preliminary stages of scope formulation and as such have a high degree of uncertainty associated with the estimates. In addition, PREPA may recommend changing these action items in future years if customer energy consumption, or vendor responses to solicitations substantially differ from those anticipated and described in this IRP.

19. Fuel price sensitivities were carried out as part of this IRP. However this aspect may have important impact on the performance of the recommended plans an should be monitored as part of the revisions on this plan.

20. The provided installation dates for equipment are a function of multiple assumptions including permitting, engineering and construction times. For those cases that the equipment is committed by the earliest assumed entry, the dates should be read as the reported date <u>or earlier</u>.

21. FOMB's "critical project" process under Section 503 of PROMESA is a separate process outside the accelerated timeline of the IRP development.

22. All new Distributed Generation connected to the system was assumed to comply and must comply with the new IEEE Standard 1547-2018 (IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces)

23. The IRP is a planning tool to be used as a guide for the development of future resources in Puerto Rico and may not have all the details necessary for the actual RFP issuance, contracting, and implementation.

24. The IRP is not a Distribution Master Plan that would require a level of effort similar to the development of this IRP. Thus, distribution investments are considered at a very high representative level.

Part
10

Action Plan

This Part summarizes the recommended actions that the Energy Bureau should approve and PREPA should undertake in the period from 2019 to 2023 to implement the Preferred Plan identified in the IRP (Action Plan). The action plans for the first five years of this IRP are the most important because they lay the foundation for the future of Puerto Rico's electrical system, which creates options for PREPA as uncertainties are resolved over time. This plan describes an ambitious program of investment and restructuring of the entire PREPA utility system to better prepare the island to withstand and recover from future weather and service disruption events and to position the island to adapt to future changes to the islands economic conditions and power requirements. The Action Plan is divided into three subsections for:

1. **Greening the Supply –** including the additions of new solar PV generation, energy storage, natural gas fueled generation and supply infrastructure, and retiring or converting all existing coal and heavy fuel oil generation.
2. **Creating a Resilient Grid** – including changes to the transmission and distribution system to support the greater resiliency including MiniGrid and microgrid operations.
3. **Engaging the Customer** – including changes to the system to support the incorporation of rooftop PV and the recommended energy efficiency and demand response programs

Each subsection describes the principle actions, timetables, capital expenditures, permitting issues and other regulatory approvals that are required to implement the plan. All project descriptions, schedules and cost estimates should be considered a best estimate at this point in time. Most of the recommended projects are at very preliminary stages of scope formulation and as such have a high degree of uncertainty associated with the estimates. In addition, PREPA may recommend changing these action items in future years should new units not become operational in time to support the planned retirements, or if customer energy consumption, or vendor responses to solicitations substantially differ from those anticipated and described in this IRP. Please refer to the Caveats and Limitations section in Part 9 of this IRP for additional details.

PREPA currently plans to solicit bids from vendors for PPOAs, facilities lease agreements, or similar commercial structures where the bidders would Design, Build and Finance, or Design, Build, Finance, Operate and Maintain the projects and sell power or use of the project to PREPA. The estimated overnight capital expenditures are provided for most of the projects listed. These estimated capital expenditures provide an indication of the magnitude of the investments that would be financed by potential vendors. The vendor financing costs would then be paid through the proceeds from a PPOA or other commercial agreement and ultimately become part of PREPA's operating expenses, as opposed to PREPA capital expenditures.

The business case for immediate action is clear. The foundational recommendations of this IRP are a) integrating the maximum amount of renewable generation that is practical to interconnect in the first four years of the planning period, b) adding distributed resources and hardening the transmission and distribution grid so that it can be segregated into eight largely self-sufficient electric islands (MiniGrids), c) increasing energy efficiency and demand response and d) retiring obsolete oil fired units and modernizing the generation fleet with LNG fueled gas turbines. These changes are essential in order to mitigate, manage and enable timely recovery from a major storm, while shifting the traditional generation from largely heavy fuel oil and distillate fuels to renewables and cleaner natural gas. The foundational recommendations of this IRP provide the system resilience, lower rates, create partnerships with the customer, and improve sustainability.

10.1 Greening the Supply

The ESM plan was selected as the recommended plan since it represents a low cost, practical option that provides the high level of renewable energy contribution and significantly improves the resiliency of the system. The ESM plan also includes flexibility that will allow PREPA to alter its implementation to follow the S4S2 or S4S2S9 plans should the Puerto Rico load and progress of the new unit additions warrant such an adjustment. The following supply resource actions summarize the plan action to implement the ESM plan. The action plans include new generation and fuel infrastructure resources, modifications to existing resources, and recommended modifications to the existing PPOA with EcoEléctrica. In addition, the section includes a discussion of the recommended activities associated with generation and fuel infrastructure additions to Yabucoa and Mayagüez that provide the ESM plan a further hedge against uncertainties.

All the new generation additions will be solicited as PPOAs. The capital expenditures presented below are provided as a reference of estimated overnight capital expenditure costs for a PPOA developer.

10.1.1 Solar Photovoltaics (install 1800 MW)

PREPA plans to install up to 1800 MW of solar PV in the first 5 years of the plan (2019 to 2023). RFPs will be issued for blocks of approximately 250 MW of solar PV, with associated BESS depending on pricing). We expect that responses to each RFP block will include multiple projects of varying capacity.

Siemens recognizes that PREPA’s current internal capabilities to interconnect may limit the PV acquisition to a significantly lower amount, however this constraint could be overcome either by the expanded capabilities of the new concessionaire or by augmenting PREPA’s internal capabilities. Siemens recognizes implementation of large-scale PV and BESS resource is challenging with PREPA’s current procurement and approval processes. This is the basis for a limit for PV acquisition, however this constraint could be overcome either by the expanded capabilities of the new concessionaire or by streamlining and augmenting PREPA’s procurement processes and internal capabilities. The urgency of adding as much PV as practical is driven by the need to provide distributed power to critical and priority loads in the minigrids as soon as possible, the compelling economics of PV vs. existing fossil generation, the pending expiration of the federal Investment tax credits and the requirement to comply with Act 17-2019. PREPA plans to solicit the solar PV projects as PPOAs and may solicit additional, alternative commercial options. In addition, PREPA plans to consider potentially soliciting the solar PV as a standalone project, solar PV plus BESS in a combined

bid and BESS as a standalone bid. A further discussion of the battery solicitations is discussed in the next sections.

The annual PV additions from the ESM plan are noted in the Exhibit below. These values should be considered an objective that could be achieved with streamlined procurement processes and enhanced capabilities either from additional PREPA resources or the new concessionaire. Expedited permitting and financial backing of the PPOA's will play a critical role.

Exhibit 10-1: ESM Annual Solar PV Additions

	2019	2020	2021	2022	2023
Solar PV Additions (MW)	0	300	480	600	420
Cumulative Additions (MW)	-	300	780	1380	1800
Capital Expenditures ($M)	-	$452	$686	$848	$586

The ESM plan under base load forecast achieved 41% renewable contribution by 2025, meeting the requirements of Act 17-2019 and 68% by 2038, exceeding the 2040 target of 60%. In fact, the plan first exceeds the 60% target in 2033.

10.1.2 Battery Energy Storage (install 920 MW)

PREPA plans to install 920 MW of BESS in the next five years. The amounts of BESS which will be installed is correlated to the capacity of solar PV installed and the resources required for the MiniGrids. The planned BESS additions are split between 200 MW with 2 hour storage capacity, 680 MW with storage capacity and 400 MW with a 6 hours storage capacity. RFPs will be issued for blocks of BESS of approximately of 150 to 200 MW. As noted in the prior Solar PV discussion, PREPA plans to consider potentially soliciting the BESS as a standalone project, solar PV plus BESS in a combined bid and solar PV as a standalone bid. The annual BESS additions from the ESM plan are noted in the Exhibit below.

Exhibit 10-2: ESM Annual BESS Additions

	2019	2020	2021	2022	2023
BESS Additions (MW)	40	200	480	80	0
Cumulative Additions (MW)	40	240	840	920	920
Capital Expenditures ($M)	$49	$211	$594	$74	-

10.1.3 Modify and Retire Existing Resources

San Juan 5&6 Combined Cycle (CC) Conversion to Natural Gas (2x200MW)

This conversion of the existing San Juan 5&6 CC units to natural gas was considered a committed action in developing this IRP and is currently an ongoing activity. The fuel conversion of San Juan 5&6 will use a ship-based liquefied natural gas (LNG) terminal. This project includes a supporting fuel infrastructure project. Each of these units has a capacity of 200 MW with a combined capacity of both units of 400 MW. Based on the current project schedule, the converted units are expected to reach commercial operation in 2019. There are

no capital expenditures for the conversion as the contract for conversion was structured as a capacity payment.

EcoEléctrica Contract Renegotiation and Extension

The PPOA contract renegotiation with EcoEléctrica is currently an ongoing activity. PREPA must renegotiate the PPOA to both modify the commercial terms and the operational flexibility of this PPOA in order to make the EcoEléctrica PPOA an economic resource in the future PREPA system. However, there is no assurance that the contract can be successfully renegotiated and extended beyond the current contract expiration in 2022. The best alternative to replace the EcoEléctrica resource, should the renegotiation and extension not be successful, is with a new gas fueled 302 MW CCGT plant at Costa Sur described below under new resources. The ESM plan would need to add the 302 MW CCGT plant at Costa Sur should PREPA will not be able to negotiate and acceptable agreement with EcoEléctrica. However, should an acceptable agreement be negotiated, Siemens would recommend that PREPA cease all activities associated with developing the new CCGT at Cost Sur.

San Juan, Aguirre 1 & 2 and Palo Seco 3 or 4 Generator Conversions to Synchronous Condensers

With the retirement of PREPA's older steam units and the introduction of greater inverter based generation from solar, wind and batteries, studies carried out under this IRP (see Appendix 1) indicate that the PREPA system will require synchronous condensers to increase the short-circuit level and provide minimum levels of voltage stability for the inverter based resources to operate reliably. The adequacy of the system short circuit level is assessed in the Industry by determining the Short Circuit Ratio as the ratio of the short circuit level in the system to the installed inverter based resources; typically values below 1.5 are problematic. Without the synchronous condensers the ratio may be under 1.0 for PREPA resulting in an unstable system.

San Juan 9 and 10 are assumed out of service for this IRP analysis and designated for either retirement or limited use. Both units are candidates for potential immediate conversion to synchronous condensers. Within the next 5 years, the ESM plan also calls for the retirement of San Juan 7 and 8 and Aguirre 1 & 2. Palo Seco 3 and 4 are designated for retirement in the ESM plan in 2025. All these units will be considered candidates for potential conversion to synchronous condensers. The specific units selected for conversion, the schedule for their conversion and the costs of conversion will require additional study. Dependent on the results of a study of the synchronous condenser needs and costs, PREPA expects to potentially convert one and possibly both of San Juan 9 and 10 to synchronous condensers within the first five years of this plan (by 2023). The estimated time to convert a unit is approximately six months. Without the benefit of the results of the study, Siemens has estimated the commercial operation date of the conversion of San Juan 10 in January 2022 and the conversion of San Juan 9 in 2023. Siemens has also developed a very high-level capital expenditure estimate of $9 million per unit for the conversion based on an EPRI study[80]. As shown in Appendix 1 with the levels of renewable generation and storage projected in this IRP, by 2025 San Juan 7 to 10, Aguirre 1 & 2 and Palo Seco 3 or 4 should be available to

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[80] Turbine-Generator Topics for Power Plant Engineers: Converting a Synchronous Generator for Operation as a Synchronous Condenser. EPRI, Palo Alto, CA: 2014. 3002002902.

operate as synchronous condensers and over the long term (by 2028) the remaining unit at Palo Seco should also be converted.

10.1.4 Unit Retirements

In the ESM the following unit retirements are identified as possible in the first five years of the plan, subject to the availability of the new generation resources, and the realization of the other assumptions in the capacity expansion plan.

It must be stressed that the IRP identified economic retirements shown below are based on several prerequisite developments which include the forecasted reduction in load, assumed levels of reliability of existing fleet remaining online until their planned retirement and the timely commissioning of the new generation resources. Please see Part 9 Caveats and Limitations and Part 8 for more details. In addition, until new generation resources become available, PREPA will need to maintain key units to ensure availability and reliability.

Exhibit 10-3: Unit Retirements

Unit	Last Year in Service
Frame 5 Peakers	2019 to 2021
Aguirre ST 1&2	2019
Costa Sur 5&6	2020
San Juan 7	2023
San Juan 8	2021

10.1.5 Install New Resources

Palo Seco CCGT (302 MW F-Class)

The ESM plans calls for a new natural gas fueled 302 MW CCGT at Palo Seco by January 2025. January 2025 is also the earliest practical date the unit could be in service. However, to meet this operation date the project would need to begin immediately. The commercial operation for this unit is estimated to be January 2025 with an estimated capital expenditure of $293 million.

Costa Sur CCGT (302 MW F-Class)

Under all cases, including the ESM, unless the contract with EcoEléctrica is successfully renegotiated and extended, it is recommended that EcoEléctrica supply be replaced by a new natural gas fueled 302 MW CCGT at Costa Sur. However, the EcoEléctrica PPOA is scheduled to expire in 2022 and it has been estimated that the earliest that a CCGT could be in service at Costa Sur is January 2025. Therefore, to preserve this earliest potential operation date for the CCGT, PREPA must start immediately and proceed with the preliminary activities for developing the CCGT in parallel with the efforts to renegotiate the EcoEléctrica PPOA. If the EcoEléctrica PPOA renegotiation is successful, the need for this unit will be reevaluated based on the load growth and the progress of the other generation development projects. The commercial operation for this unit is estimated to be January 2025 with an estimated capital expenditure of $293 million.

Mobile Gas Turbine Peaking Units (18x23 MW)

The ESM plan calls for installation of 18 GTs, of 23 MW each, distributed at five different plant locations around the island with preference for those locations where the exiting 21 MW Frame 5 units are located. These new units will be capable of burning containerized natural gas delivered by truck with onsite tankage. The units are required to provide reliable distributed generation to serve critical and priority loads within the MiniGrids. Since these, are mobile generator units, the additional two units recommended with the ESM case will provide PREPA greater flexibility to move the units to other MiniGrids if needed. The units will be distributed as shown in the Exhibit below:

Exhibit 10-4: Locations of Mobile 23 MW GTs

Location	Number of Units
Jobos	2
Mayagüez North	4
Carolina (Daguao)	5
Caguas (Yabucoa)	5
Cayey	2
Total	18

These small GTs should be placed in service as soon as practical. . The ESM plan assumes a January 2021 commercial operation date and an estimated capital expenditure for all 18 units of $433 million.

10.1.6 New Natural Gas Infrastructure

In this section, Siemens presents the additional new fuel infrastructure and associated timing and costs for PREPA to remain competitive and lower rates.

San Juan Land-Based LNG Terminal

This new LNG terminal is recommended as a preferred option for supplying large quantities of natural gas to the San Juan and Palo Seco plants. The project would provide a land-based (onshore) LNG storage and vaporization facility near the San Juan plant supplied with LNG carrier delivery directly to onshore tanks. The project also includes a natural gas pipeline from San Juan to the Palo Seco Plant to support the new 302 MW CCGT recommended at the Palo Seco plant. ESM, S4S2 and S4S2S9 all assume operations by 2025. Any delays in the development of the land-based LNG supply is assumed to be covered by ship-based LNG. The LNG terminal

Based on input from PREPA, the estimated capital cost of the land-based LNG facility was estimated to be $472 million with a capacity of 125.88 million cubic feet per day (MMcf/d) as necessary to simultaneously supply the converted San Juan 5&6 CC (2x200 MW) and one F-class CCGT at Palo Seco (302 MW) dispatched at full capacity. To this CapEx, the costs of a pipeline from San Juan to Palo Seco was added. This cost was estimated to be $25 million for one CCGT. In the case that more than one CCGT would have been added by the model an incremental CapEx of $200 million for the additional gasification (3.4 MMcfd) would need

to be added as well as $15 million for an increased capacity pipeline (35 million total). Please see workpaper PREPA Fuel Price Designation (Conversion Cost details)_v2.xlsx

10.1.7 Additions to Preserve Options and Hedge Uncertainties

As discussed in Section 1, Siemens recommends that select elements of the ESM plan serve a hedge against uncertainties. The projects described below for new LNG infrastructure, generation additions and fuel conversions at Yabucoa and Mayagüez are part of the LTCE portfolio for the ESM but not part of the S4S2 or S4S2S9 plans. Should the customer load or generation projects at other sites indicated an adjustment is warranted. The intent would be to proceed only with the preliminary permitting and engineering for these project and then reevaluate their need, prior to making any large contractual commitments for equipment purchase or construction.

Yabucoa Ship-Based LNG Terminal & Yabucoa CCGT (302 MW F-Class)

The addition of an LNG terminal at Yabucoa, and the associated 302 MW CCGT discussed below, is part of some of plans, including the ESM cases, but was not selected for the S4S2 cases. The planned commercial operation of the terminal and the CCGT is planned January of 2025. However, to meet this operation date the project would need to begin immediately. Siemens estimates the capital expenditures for ship-based LNG delivery to Yabucoa to be $285 million should it proceed to commercial operation. The commercial operation for this unit is estimated to be January 2025 and an estimated capital expenditure of $293 million should it proceed to commercial operation. However, Siemens recommends that PREPA only proceed the preliminary permitting and engineering for this to preserve the ability to meet the potential 2025 operation if needed. We recommend the need for this project be reassessed prior to initiation of any equipment or construction commitments.

Mayagüez Ship-Based LNG Terminal, Peaker Conversion to LNG Natural Gas (4x50MW) and CCGT (302 MW F-Class)

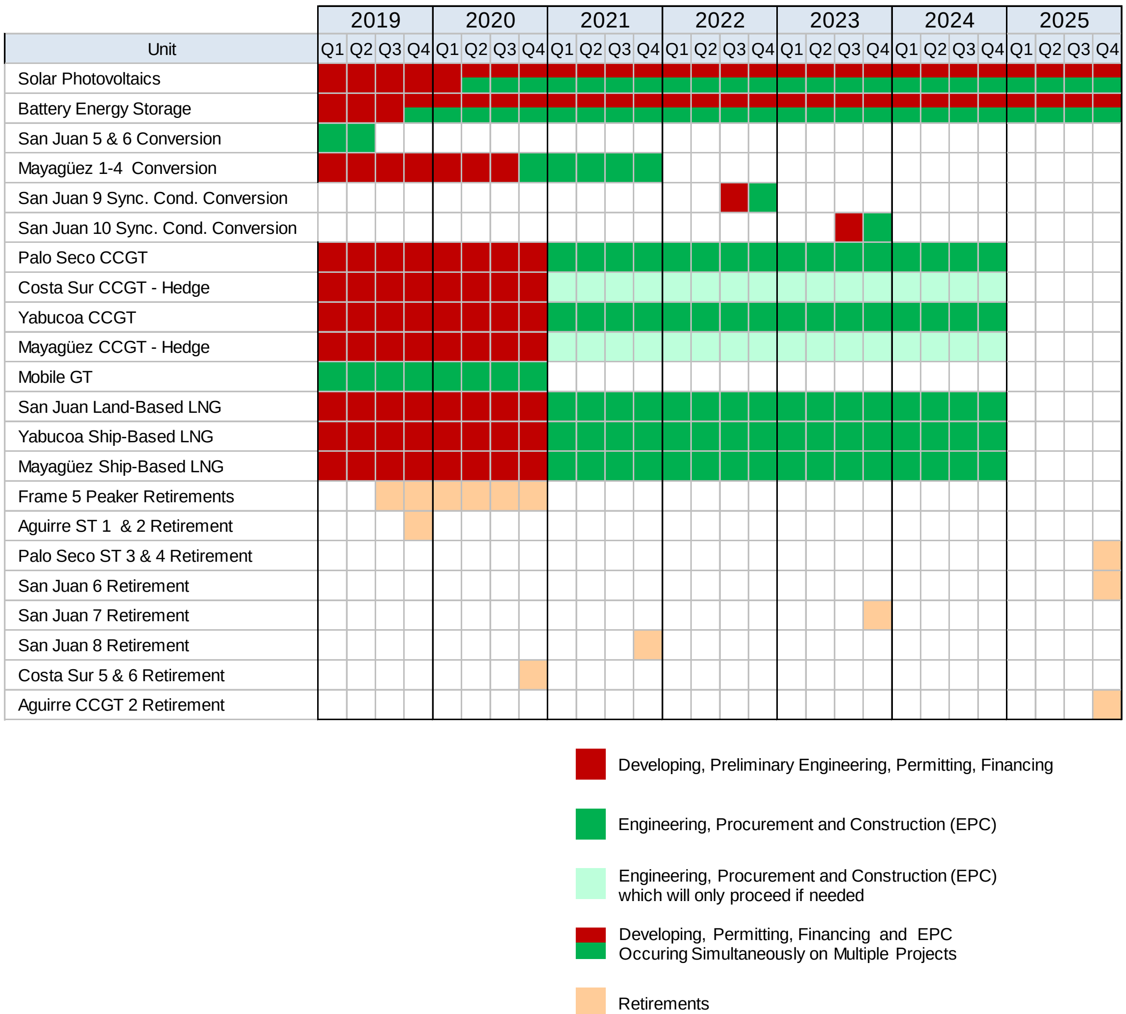
The addition of an LNG terminal at Mayagüez, and the associated conversion of the existing Peaker units to natural gas is in the ESM cases but was not selected for the S4S2 cases. The recommended commercial operation date called for in the ESM base case is January 2023 for the LNG infrastructure and the Peaker conversations. A new 302 MW CCGT was also considered for this site an alternative to the other large CCGT projects that have a commercial operation date of January 2025. The estimated capital expenditures are $215 million for the ship-based LNG infrastructure, $5 million for the conversion of the Peaker units and $293 million for the new 302 MW CCGT. However, Siemens recommends that PREPA only proceed the preliminary permitting and engineering for the projects for this site to preserve the ability to meet the potential 2025 operation if needed. We recommend the need for these projects be reassessed prior to initiation of any equipment or construction commitments.

10.1.8 Summary Timetable

A summary timetable for the projects discussed above is shown in the Exhibit below. The table presents the construction projects for the generation, batteries synchronous condensers and the natural gas infrastructure. The new projects include the two CCGT projects, at Costa Sur and Mayagüez for which Siemens recommends the preliminary engineering and permitting activities proceed but their potential need be reevaluated prior to any construction or equipment procurement commitments. The Solar and Battery project additions indicate on the schedules and timetable legend that since multiple projects will be continuously proceeding on different schedules, EPC will be

occurring on some projects while others will still be in the preliminary permitting and engineering phase. Finally, the expected retirements are also shown in the timetable. As discussed early in this report, the actual retirement dates may shift if any of the new generation projects are delayed or other circumstances dictate the continuing need for the units.

Exhibit 10-5: Summary Schedule



10.1.9 Summary of Capital Expenditures

A summary of the estimated overnight capital costs is provided in the Exhibit below.

Exhibit 10-6: Summary of Capital Expenditures for 2019 to 2023 ($millions)

Project	2019	2020	2021	2022	2023
Solar Photovoltaics	-	$452	$686	$848	$586
Battery Energy Storage	$49	$211	$594	$74	-
San Juan 10 Sync. Cond.	-	-	-	$9	-
San Juan 9 Sync. Cond.	-	-	-	-	$9
Palo Seco CCGT	-	-	-	-	-
Costa Sur CCGT	-	-	-	-	-
Mobile GTs	-	-	$433	-	-
San Juan Land-Based LNG	-	-	-	-	-
Yabucoa Ship-Based LNG	-	-	-	-	-
Yabucoa CCGT	-	-	-	-	-
Mayagüez Ship-Based LNG	-	-	-	-	-
Mayagüez Peaker Gas Conversion	-	-	-	-	-
Mayagüez CCGT	-	-	-	-	-
Total	$49	$663	$1,713	$931	$595
Total for all Projects 2019 to 2023	$3,951				

The lines in the table above with no dollars shown for the project are projects that are started in the timeframe shown but do not reach commercial operation by 2023. In the case of the Costa Sur CCGT and the Yabucoa CCGT, these project are not included in the ESM case but are recommended to proceed with preliminary permitting and engineering activities to preserve the options of a commercial operation date 2025, should conditions evolve so these projects are needed.

10.1.10 Permitting and Regulatory Activities

This IRP require that all major expenditures and contracts commitments referenced in this document, the approval from the PREB.

In addition, the action plan described above will require a host of additional approvals from the government of Puerto Rico and federal government agencies. The approval includes air, water and land use permits associated with the design, construction and operation of the generating projects. A partial list of likely permits associated with the new resources and gas infrastructure include:

- EPA and EQB review of New Source Review (NSR) for air emission permitting
- EPA National Pollutant Discharge Elimination System (NPDES) for water permitting
- EQB Water Quality Certification
- Environmental Assessment (EA) or Environmental Impact Statement (EIS) reviewed by various Puerto Rico and federal agencies
- Puerto Rico Office of Permits Management (OGPe) Construction Permits

While PREPA will need to support these applications and permits for all the projects listed, PREPA expects the project bidders will provide vast majority of the work and expenses associated with any required permits.

10.2 Creating a Resilient Grid

The MiniGrid architecture is the foundation for the future of Puerto Rico's electrical system. The recommendations contained in this section work together synergistically. The system should be understood from the grid first, with the concomitant supply side and demand side resources integrated into each MiniGrid.

10.2.1 Transmission Principal Recommendations

PREPA has identified a comprehensive list of transmission system related projects to both bring the existing transmission facilities up to current or new standards as well as the new construction and infrastructure hardening of transmission lines (underground cables) and transmission substations for MiniGrid operations. This forms a large portfolio of transmission capital investments for which a prioritized implementation plan and an estimated timeline is essential.

The projects are mainly focused on enabling PREPA's transmission system to operate as multiple MiniGrids during or shortly after a major event, and before the infrastructure can be restored to integrated system operations.

All projects are categorized by various technical justifications, most of which are directly associated with the formation of MiniGrids, i.e. MiniGrid Main Backbone, MiniGrid Backbone Extension, Interconnection of Critical loads, and Interconnection of MiniGrids. There are some projects under existing infrastructure hardening category and aging infrastructure replacement that are related to the reliable operation of the MiniGrids. Most of the transmission substation projects are related to converting the existing substations into gas insulated substations.

In addition to the MiniGrid directed projects, there is a second major category of projects; the transmission reliability investments that are necessary to bring back PREPA system up to current or new Standards, reconstruct aging infrastructure and allow reliable day to day operations.

A total of five (5) groups of priority; Priority 1 through Priority 5, have been determined by PREPA and assigned to each project. Critical operational and field related construction coordination issues were considered by PREPA to assign the projects to an appropriate priority group related to scheduling. Projects deemed Priority 1 will be assumed to have the engineering/permitting/outage scheduling work start as early as July 2019; engineering, procurement and construction (EPC) start early in 2020; and commercial in-service dates are as soon as March 2021. Projects in Priority 2 group will start upon completion of EPC work of all Priority 1 projects, with an in-service date from 2023 to 2024, and continuing for the remaining priority groups. The above timeline assumption should be considered a high level estimate at this time and should be refined with detailed planning that considers which project tasks can be carried out in parallel without compromising the reliability of the system. The detailed plan also should identify when long lead time items should be ordered. Our current working assumption is that long lead time items should be ordered during the engineering and permitting phase and prior to the EPC start. The action plan focuses mainly on the first 5 years for investment implementation; therefore, the detail list of projects will only show projects identified with Priority 1 and Priority 2.

The confidential Attachment B provides the detailed list of Priority 1 and Priority 2 transmission line and substation investment projects.

10.2.2 Schedule of Capital Expenditures

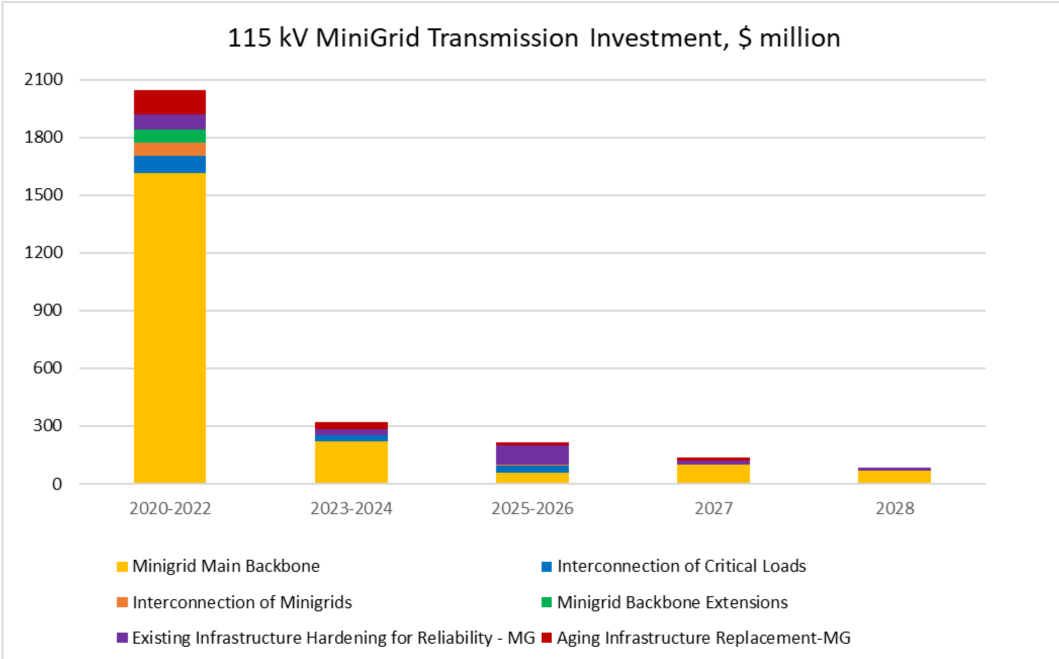
The exhibits below show the schedule of 115 kV and above transmission capital expenditures for MiniGrids over the next 10 years. EPC work starts in 2020 for Priority 1 group projects followed by Priority 2 group projects in 2023 and so on. We have spread the capital investment into three years for Priority 1 projects due to its large total capital expenditures of $2,048 million (Avg. $683 million per year). EPC work for Priority 2 group projects will start in 2023 and spread across two years, totaling $322 million (Avg. $161 million per year).

For the PREPA's transmission system to be operable in MiniGrid mode, and as discussed in detail in Appendix 1 Transmission & Distribution Design of this IRP, additional microgrid controllers and communication infrastructure for Minigrid control system is necessary. The investment expenditure is very small ($0.135 million per microgrid controller for each MiniGrid or microgrid) compared to the capital investment on transmission projects, and thus will not be listed separately in this section. However, the investment on microgrid control system should be assigned as Priority 1 group so that they will be implemented as early as possible.

Exhibit 10-7. 115 kV MiniGrid Transmission Investment, 2018 $ million

	Priority 1	Priority 2	Priority 3	Priority 4	Priority 5
Technical Justification	**2020-2022**	**2023-2024**	**2025-2026**	**2027**	**2028**
Interconnection of Critical Loads	87.9	31.7	36.0	0.0	0.0
Interconnection of Minigrids	66.8	0.0	6.8	0.0	0.0
Minigrid Backbone Extensions	70.4	0.0	0.0	0.0	0.0
Minigrid Main Backbone	1615.7	220.2	59.1	101.9	70.3
Existing Infrastructure Hardening for Reliability -	80.9	31.5	100.3	20.8	11.1
Aging Infrastructure Replacement-MG	126.0	38.8	11.3	15.5	5.0
Total	**2047.7**	**322.2**	**213.5**	**138.3**	**86.4**

Exhibit 10-8. 115 kV MiniGrid Transmission Investment, 2018 $ million

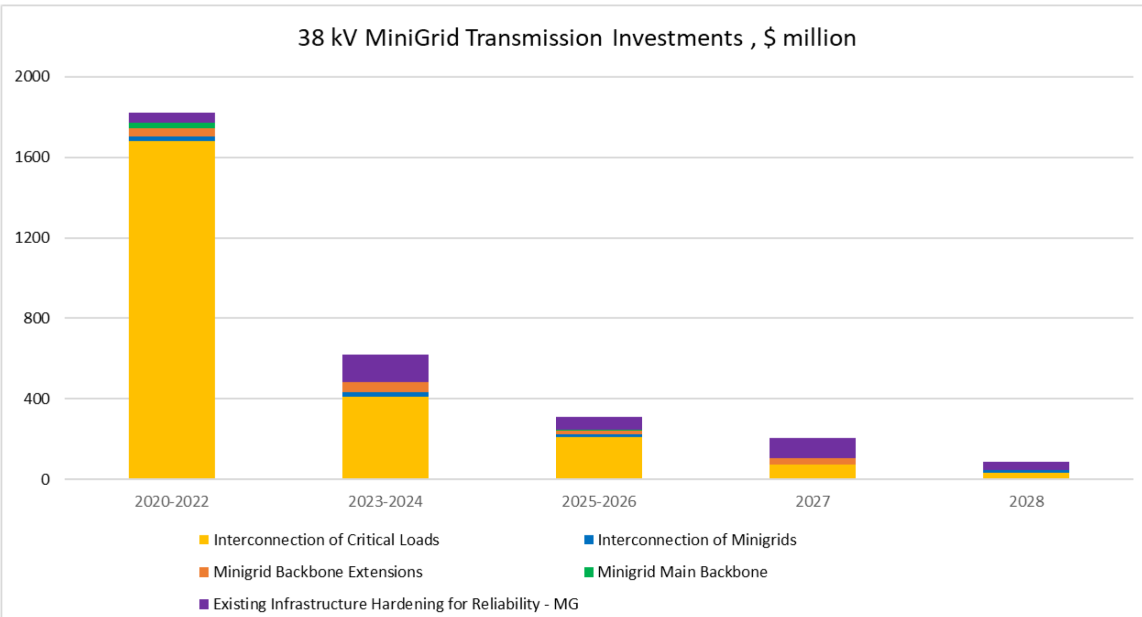


Exhibits below show the schedule of 38 kV transmission capital expenditures for MiniGrids over the next 10 years. EPC work starts in 2020 for Priority 1 group project followed by Priority 2 group projects in 2023 and so on. Again, we have spread the capital investment into three years for Priority 1 projects due to its large total investment of $1,821 million (Avg. $607 million per year). EPC work for Priority 2 group projects will start in 2023 and spread into two years, totaling $619.4 million (Avg. $310 million per year).

Exhibit 10-9. 38 kV MiniGrid Transmission Investment, $ million

	Priority 1	Priority 2	Priority 3	Priority 4	Priority 5
Technical Justification	**2020-2022**	**2023-2024**	**2025-2026**	**2027**	**2028**
Interconnection of Critical Loads	1678.5	413.1	212.8	75.3	33.1
Interconnection of Minigrids	24.7	20.9	9.7	0.0	13.6
Minigrid Backbone Extensions	38.9	49.0	18.9	28.5	0.0
Minigrid Main Backbone	28.7	0.0	6.9	0.0	0.0
Existing Infrastructure Hardening for Reliability -	49.9	136.4	64.3	101.3	42.4
Total	**1820.6**	**619.4**	**312.6**	**205.1**	**89.2**

Exhibit 10-10. 38 kV MiniGrid Transmission Investment, $ million

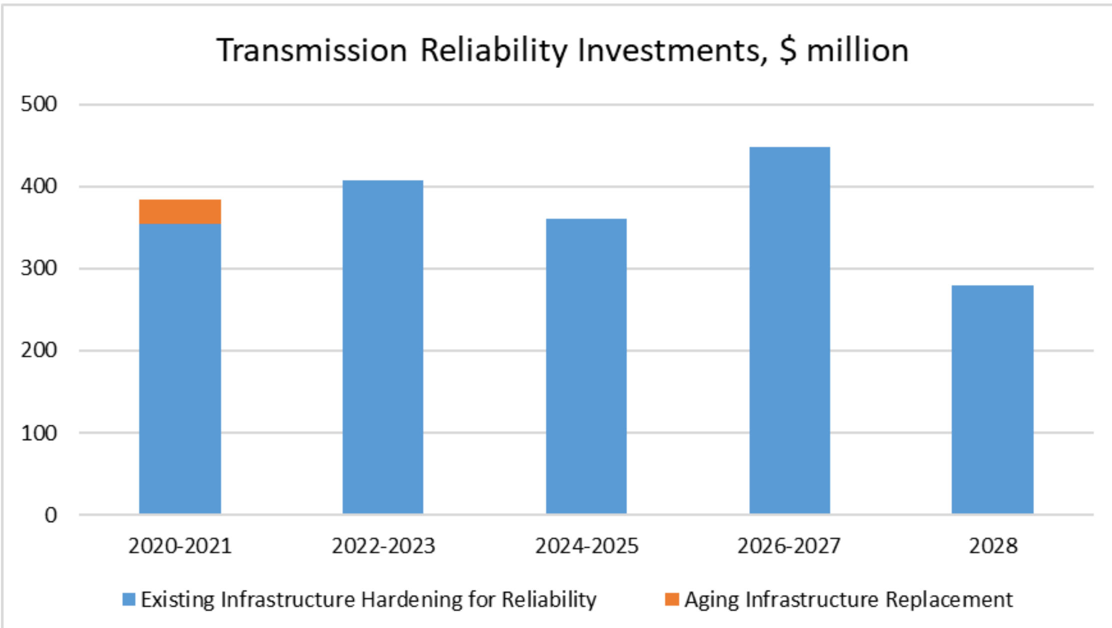


Exhibits below show the schedule for the transmission reliability upgrades capital expenditures that are required for reliable of normal operation and not related to the MiniGrid. EPC work starts in 2020 for Priority 1 group project followed by Priority 2 group projects in 2023 and so on. Once again, we have spread the capital investment into two years for Priority 1 projects, totaling $383.1 million (Avg. $191.6 million per year). EPC work for Priority 2 group projects will start in 2022 and spread through two years, totaling $408.1 million (Avg. $ 204 million per year).

Exhibit 10-11 Transmission Reliability Investment, $ million

	Priority 1	Priority 2	Priority 3	Priority 4	Priority 5
Technical Justification	**2020-2021**	**2022-2023**	**2024-2025**	**2026-2027**	**2028**
Aging Infrastructure Replacement	28.8	0.0	0.0	0.0	0.0
Existing Infrastructure Hardening for Reliability	354.4	408.1	359.8	448.6	279.8
Total	**383.1**	**408.1**	**359.8**	**448.6**	**279.8**

Exhibit 10-12. Transmission Reliability Investment, $ million

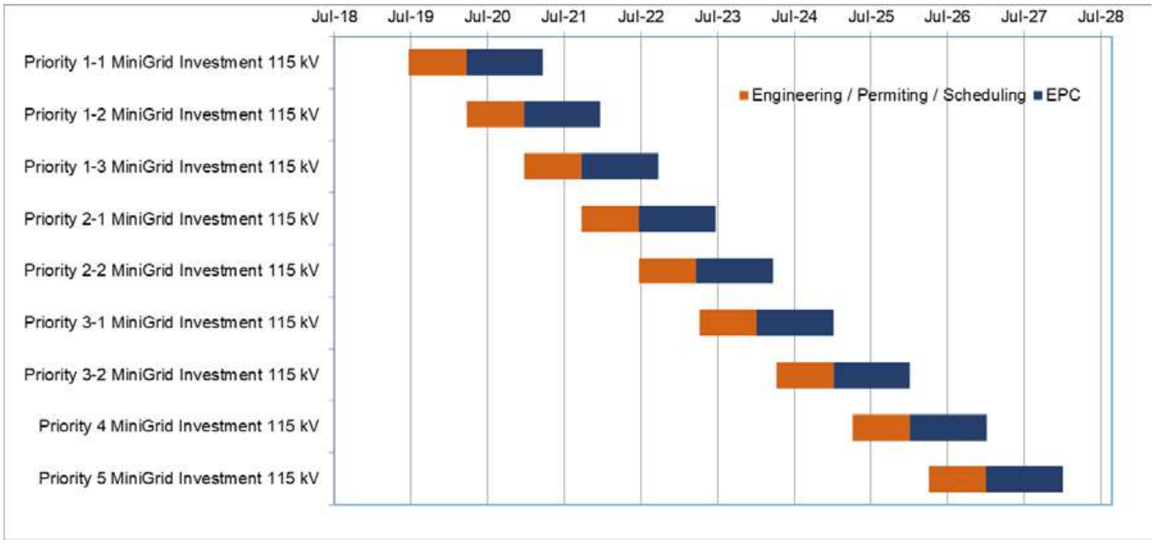


10.2.3 Timetables

The Exhibit below shows the timetables of 115 kV and above MiniGrid transmission investment implementation for both the engineering/permitting/outage scheduling phase and EPC phase.

Priority 1 and 2 projects are estimated to be completed before 2024, and all projects are assumed to be in service by 2028.

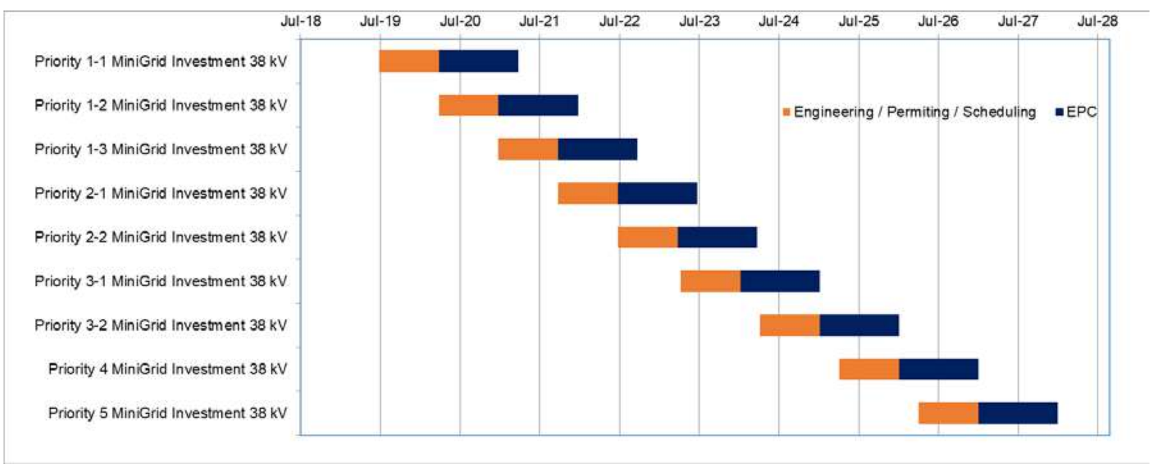
Figure 10-13. 115 kV MiniGrid Transmission Investment timeline



The exhibit below shows the timetables of 38 kV transmission line and 115/38 kV substations MiniGrid transmission investment implementation for both the engineering/permitting/outage scheduling phase and EPC phase.

Similarly, Priority 1 and 2 projects are estimated to be completed before 2024, and all projects are assumed to be in-service by 2028.

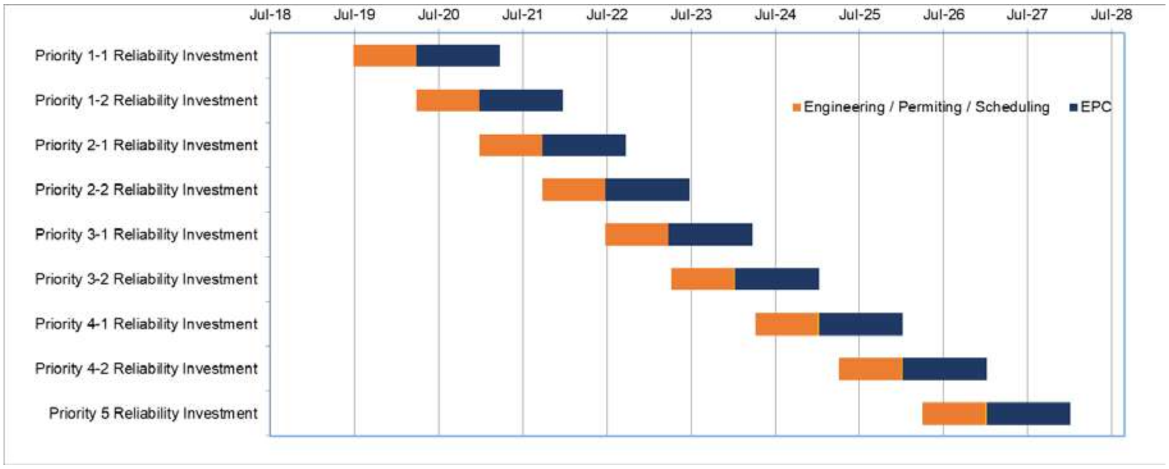
Exhibit 10-14. 38 kV MiniGrid Transmission Investment, timeline



The Exhibit below shows the timetables of transmission reliability upgrades not related to MiniGrid investment implementation for both the engineering/permitting/outage scheduling phase and EPC phase.

Priority 1 and 2 projects are estimated to be completed before 2023, and all projects are assumed to be in-service by 2028.

Exhibit 10-15. Transmission Reliability Investment, timeline



10.2.4 Permitting and Regulatory Activities

The action plan described above will require a host of additional approvals from the Puerto Rico and federal government authorities and agencies.

Permitting: The approval includes air, water and land use permits associated with the design, construction and operation of the transmission projects. Environmental Assessment (EA) or Environmental Impact Statement (EIS) reviewed by various Puerto Rico and federal agencies and Puerto Rico Office of Permits Management (OGPe) and construction permits.

Siting Approval: Most high-voltage transmission projects will require the state siting approval. Project sponsors will need to carry out environmental and detailed engineering work in order to establish a highly-detailed project plan to support the application.

Wetlands and Waterways: Any proposed project should be sited to avoid and minimize impacts to wetlands or other areas of environmental concerns. If the project cannot avoid such impact, it is expected to be subject to regulations certain additional permitting programs, namely Section 401 and Section 404 of the Clean Water Act, Section 10 of the Rivers and Harbors Act. Detailed analyses will be conducted for siting and routing for the specific permit.

Other Minor Permits: In addition to the above, some other minor permits may be required for any construction. These include permits related to airspace clearance, stormwater/erosion and sedimentation control, road crossings, and utility and railroad crossings.

While PREPA will need to support these applications and permits for all the projects listed, PREPA expects the project bidders will provide vast majority of the work and expenses associated with any required permitting activities.

10.3 Engaging the Customer: Distribution System, Energy Efficiency and Demand Response.

Customer engagement is critical to the future operation of Puerto Rico's energy system. The upgrades in the distribution system and concomitant acceleration of energy efficiency and demand response allow customers to play a meaningful role in Puerto Rico's electricity grid.

10.3.1 Distribution System

The investments in the distribution system are designed to achieve the following objectives:

a) Ensure resiliency of supply to the end customer at a level consistent with the improvements made at the generation and transmission levels for the formation of the MiniGrids and with initial focus on Critical and Priority Loads.

b) Support the integration of distributed energy resources and, in particular, roof top solar.

To achieve these objectives Siemens, with the collaboration of PREPA, assessed the types of load (Critical, Priority or Balance) served by each of the feeders in PREPA's system and created a priority conversion index based on the criticality of the load served and the condition of the assets serving the load.

With the procedure above, we identified the air insulated substations that should be upgraded to GIS to ensure their survivability from a major hurricane and that were served by transmission substations that were either going to be upgraded, according to the investment plan discussed earlier, or already had an adequate level of reliability and needed no upgrade. Further, Siemens coordinated the timing of the upgrade at the transmission and distribution levels so that the projects would be done in parallel as much as possible. Finally, in the conversion to GIS, priority was given to those substations with voltages under 13.2 kV, as the system should be normalized to that voltage and there is a strong correlation of aging infrastructure, particularly those at the lowest primary distribution system voltage of 4.16 kV.

The CapEx for substations was estimated using PREPA's 3 main designs depending on load served, as shown in the exhibit below.

Exhibit 10-16. PREPA's preferred substation designs (MV – 13.2 kV)

	MVA	Cost GIS	Transformer	Installation Labor+ Material+ Overhead + Testing & commissioning	Total
S/S 1	22.4	530,661	651,300	354,588	1,536,549
S/S 2	33.6	530,661	976,950	452,283	1,959,894
S/S 3	44.8	530,661	1,302,600	549,978	2,383,239

For the feeders we followed a similar procedure as for the substations, and in this case, we identified the feeders that, given the criticality of the load served, should have their mainlines (also called backbone or trunk-lines) rebuilt from overhead to underground cables. As before,

priority was given to feeders with voltages under 13.2 kV and that were associated to substations that were going to be upgraded to GIS or already had adequate levels of reliability.

For the estimation of the investments, we considered maintaining the overall ampacity of the mainline using PREPA's standardized underground cables as shown in the exhibit below. No CapEx for voltage conversion to 13.2 kV was provided as this is highly dependent on the assets on site.

Exhibit 10-17. PREPA's Mainline Conductor Replacement

	Ratings (amps)			Ratings (amps)
PREPA O/H Conductors	Normal	Emergency	Replacement	Normal
1/0 AAAC	212	239	4/0 XLPE	305
1/0 ACSR	221	243	4/0 XLPE	305
2/0 ACSR	252	278	4/0 XLPE	305
3/0 SPACER 15 KV	265	298	4/0 XLPE	305
1/0 CU	269	303	4/0 XLPE	305
3/0 AAAC	284	321	4/0 XLPE	305
3/0 ACSR	289	318	4/0 XLPE	305
2/0 CU	311	352	500 XLPE	485
4/0 ACSR	328	361	500 XLPE	485
3/0 CU	360	407	500 XLPE	485
3/0 CU XLP 15 KV	360	407	500 XLPE	485
266 ACSR SPACER	382	436	500 XLPE	485
266 ACSR	418	466	500 XLPE	485
250 CU	461	523	500 XLPE	485
336 ACSR	483	540	500 XLPE	485
336 SPACER	483	540	500 XLPE	485
300 CU	500	550	750 XLPE	584
556 SPACER	600	700	750 XLPE	584
556 ACSR	650	700	750 XLPE	584
652.4 AAAC	651	450	750 XLPE	584
500 CU XLP 15 KV	709	808	750 XLPE	584
795 ACSR	824	925	750 XLPE	584

	Unit Costs $2016			
	Conductor	**Ducts**	**Total**	**Total $ 2018**
	US$/Mile	US$/Mile	US$/Mile	US$/Mile
4/0 XLPE	240,298	220,104	460,402	484,000
500 XLPE	366,699	276,673	643,372	676,000
750 XLPE	465,084	276,673	741,756	779,000

For the incorporation of photovoltaic (PV) systems, Siemens conducted a high level estimation of the possible impact of the projected rooftop PV growth in the next five years conservatively, assuming that it occurs in the feeders where there are already installations. This analysis identified those feeders where it is possible that there would be voltage regulation issues, localized overloads or the risk of reverse power flows to the transmission system.

For the screening of feeders where there could be a risk of voltage regulation issues (possibly requiring installation of voltage regulation equipment), we identified those feeders where either the aggregated rooftop generation was close to (90% threshold assumed) or exceeded the noon time load on the feeder, or where it represented more than 30% of the feeder capacity, as determined considering the nominal voltage and the conductor at the substation exit.

For the determination of those feeders where overload could be possible and should be investigated, we identified those feeders where, if the aggregated PV was located downstream of the smallest mainline conductor and lowest feeder voltage[81], there would be an overload and the mainline would need to be upgraded.

Finally, we identified those feeders where, during noon-time light load conditions, there would be a risk of reverse power flow, necessitating the upgrade of the protection equipment and settings and, under some situations, the addition of voltage regulation equipment.

With this approach, we identified a group of 4.16 kV feeders that are strong candidates to upgrade to 13.2 kV.

It is important to point out that the distribution analysis above can only be used for screening purposes and it is not a substitute for the necessary detailed system studies that must consider the feeder topology, assets in service, and location of the load and PV systems. This future detailed analysis, which is beyond the scope of this evaluation, must include an evaluation of the expected performance of equipment; refinement of the definition of the necessary improvements, capital expenditures, and timing to implement the projects.

Similar to the transmission investments mentioned above, for distribution substation and feeder upgrades, a total of four (4) groups of priority, Priority 1 through Priority 4, have been selected considering the priority (timing) of the associated transmission projects and the intrinsic importance of the distribution investment for a reliable and resilient electricity supply of the critical and priority loads. As was the case in the transmission system evaluation, Priority 1 projects will be assumed to have the engineering/permitting/outage scheduling work start as early as July 2019, with engineering, procurement and construction (EPC) starting early 2020, and commercial in-service data as soon as March 2021. Projects in Priority 2 group will start upon completion of EPC work of all Priority 1 projects, with in-service date from 2023 to 2024. The above timeline is a high level estimation at this time and will be refined once the necessary distribution studies have been carried out. The action plan focuses mainly on the first 5 years for investment implementation, therefore, we provide below a list of Priority 1 and Priority 2 substations and feeders that were identified as targets for upgrade by our resiliency screening assessment. This screening does not include an evaluation of the actual assets of the distribution system, the particular operational limitations, nor a thorough on-site assessment. The Appendix 1 and associated workpapers, contains the substations identified for upgrade considering the three PREPA's standardized sizes and

[81] PREPA's Voltage Conversion Policy requires upgrading the distribution system primary voltage to 13.2 kV. As part of this voltage conversion process, PREPA has feeders that operate at multiple primary distribution voltages. For example, it has feeders with a source voltage of 13.2 kV that include step-down power transformers to supply loads at lower voltages (8.32 kV, 7.2 kV and 4.16 kV).

designs as presented earlier. Also, as will be noted in that document there are 19 substations in the list have already been identified by PREPA and FEMA for upgrade/relocation.

Appendix 1 contains on the feeders identified for undergrounding of the mainline based on the criticality of the load served and other aspects discussed above.

Finally, 45 feeders were identified as potentially having issues with the interconnection of PV systems in the next 5 years, of which 30 (66%) have at least one section at 4.16 kV and it would highly benefit from upgrading to 13.2 kV. The exhibit below shows the total number of feeders identified as candidates for requiring upgrades for the integration of distributed generation (Appendix 1 provides additional details).

Exhibit 10-18. Number of Feeders with potential issues for integration of rooftop PV systems in the next 5 years

Min Nominal Voltage (1)	Voltage Issues Possible (2)	Overload Issues Possible (3)	Reverse Flow Possible (4)
4.16	21	10	23
7.2	1	1	0
8.32	4	1	4
13.2	9	1	8

(1) If there are two voltages on a feeder this is the lowest voltage and it is used to determine the potential for overload (e.g. the DG is downstream of the step down transformer)

(2) Voltage issues could happen if the PV is greater than 30% of the feeder capacity at the s/s exit (highest nominal voltage and largest conductor) or if greater than 90% of the light load

(3) Calculated using the smallest conductor section at the mainline and lowest voltage (i.e. the DG is downstream)

(4) If the DG is greater than 80% of the light load.

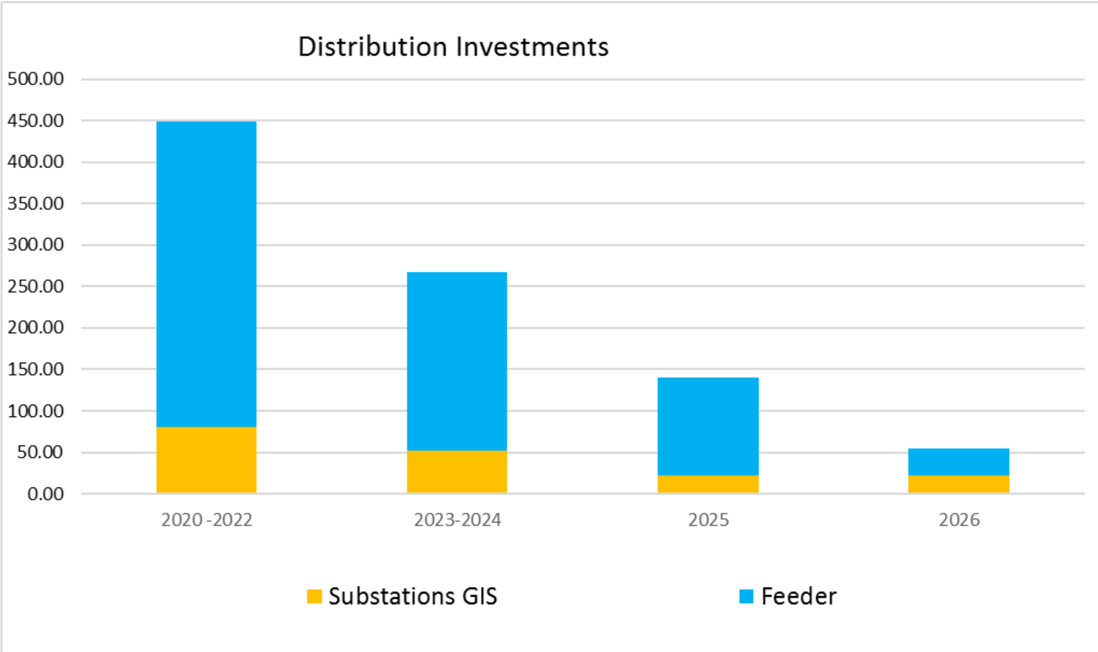
10.3.2 Schedule of Capital Expenditures

The exhibits below show the schedule for substation conversion to GIS and undergrounding of feeders for the next 10 years. EPC work starts in 2020 for Priority 1 group projects, followed by Priority 2 group projects in 2022, and so on. The timing is selected to match the transmission system investments.

Exhibit 10-19. Distribution Investments, 2018$ million

	Priority 1	Priority 2	Priority 3	Priority 4	
	2020 -2022	2023-2024	2025	2026	Total
Substations GIS	81.17	52.40	21.94	21.67	177.17
Feeder	367.89	214.59	118.93	32.90	734.31
Total	**449.06**	**266.99**	**140.86**	**54.57**	**911.48**

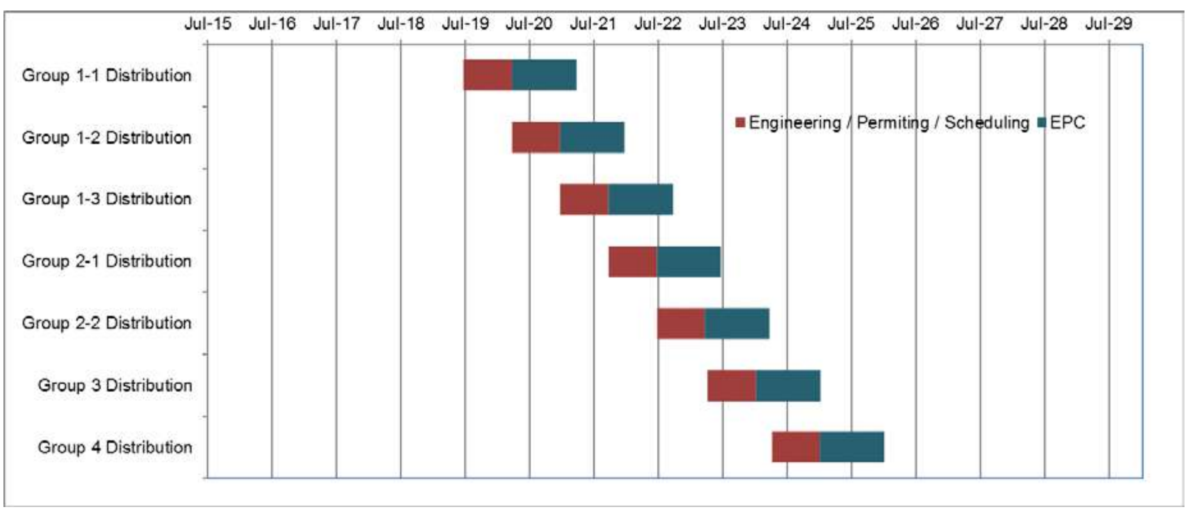
Exhibit 10-20. Distribution Investment, 2018$ million



10.3.3 Timetables

The Exhibit below shows the timetables for the distribution investments (GIS substation conversion and feeders). It is noted that both Group 1 and 2 are expected to be completed by 2024, which is an aggressive timeline, but in line with the importance of these investments.

Exhibit 10-21. Distribution Investment timeline



10.3.4 Permitting and Regulatory Activities

The action plan described above will require a host of additional approvals from the Puerto Rico and federal government authorities and agencies. These are expected to be similar to

those for transmission albeit of lesser scope and faster timelines. The main challenge for distribution will be the scheduling of multiple projects and the coordination with transmission.

10.3.5 Accelerating Energy Efficiency

Energy efficiency is always the least cost resource and lower demand at far less cost than new supply and associated transmission and distribution. The action plan calls for establish Energy Efficiency (EE) and with the objective of reducing the demand in values approximating the 2% per year, (as defined in Part 3 – Load Forecast)   Energy efficiency can add over 600 GWh of reduced demand by 2025.

10.3.6 Enabling Demand Response

Demand response supports both reliability and resilience goals by partnering with the customer to tap their inherent operational flexibility. Demand response programs become increasingly important as renewable penetration rises. The action plan calls for establishing Demand Response (DR) programs with a goal of over 60 MW of flexibility to the system by 2025.   Reinforce the distribution system and enable two-way flow of energy and providing voltage regulation and flicker control to facilitate the high penetration of distributed energy, as forecasted in this IRP (see Appendix 4 – Demand-Side Resources).

10.3.7 Timetables

The Energy Efficiency initiatives and demand response are long term programs with multiple components. Please see Appendix 4 for details.

Attachment
A

Gas Pipeline Competition Model

Gas Pipeline Competition Model (GPCM®)

Siemens utilizes the Gas Pipeline Competition Model (GPCM®) to provide rigorous natural gas market evaluations. GPCM® is an industry-leading modeling tool that Siemens license and adapt to include the most up-to-date assumptions on supply, demand, and infrastructure. These assumptions are updated every quarter, with a full review of inputs in the spring and fall (coordinated with Siemens power market modeling work) and a short-term calibration every summer and winter. With GPCM® Siemens cover the entire interconnected North American natural gas market, including the evolving Mexican natural gas (and related power) market.

For inputs, Siemens utilize leading data sources such as DrillingInfo's ProdCast® tool for natural gas production forecasting. ProdCast® allows Siemens to input its oil and gas price assumptions into the model, providing an iterative calibration opportunity to better refine the supply outlook. On the demand side, Siemens develop its outlook from primary sources, including its own electricity market modeling for power sector natural gas demand. Finally, Siemens regularly monitor updates in pipeline infrastructure in-service dates, capacities, and regulatory requirements to ensure Siemens have the latest outlook for pipeline buildout in its modeling.

As an output from GPCM®, Siemens provide short-term and long-term price and basis forecasting for all major natural gas market and supply area liquid trading points in North America as well as economic pipeline flow analysis. Minor, illiquid, or retired natural gas trading points can also be modeled, upon request. Siemens National model outlook can be customized in the model in many different ways to test variables such as a pipeline cancellation, an unexpected growth or decline trend in production from a particular play, the impact of a new major LNG export facility, or any other number of Scenarios.

GPCM® Model Structure and Capabilities

Mathematically, GPCM® is a network model that can be diagrammed as a set of "nodes" and "arcs". Nodes represent production regions, pipeline zones, interconnects, storage facilities, delivery points, and customers or customer groups. The connections between these nodes are called arcs, which represent transactions and flows. Some of these are supplier deliveries to pipelines, transportation across zones and from one zone to another, transfers of gas by one pipeline to another, delivery of gas into storage, storage of gas from one period to another, withdrawal of gas from storage, and pipeline deliveries of gas to customers.

GPCM® dynamically solves for economic rents, allowing cheaper supplies to be used before more expensive supplies and enabling customers willing to pay more to be served before those willing to pay less. By including the entire system of North American gas production,

transmission, storage, consumption, and imports/exports, GPCM® optimizes gas flows in an economically sensible order to produce an economically efficient, market-clearing solution. GPCM® contains more than 200 existing and proposed pipelines, 400 storage areas, 85 production areas, 15 liquefied natural gas (LNG) import/export terminals, and nearly 500 demand centers.

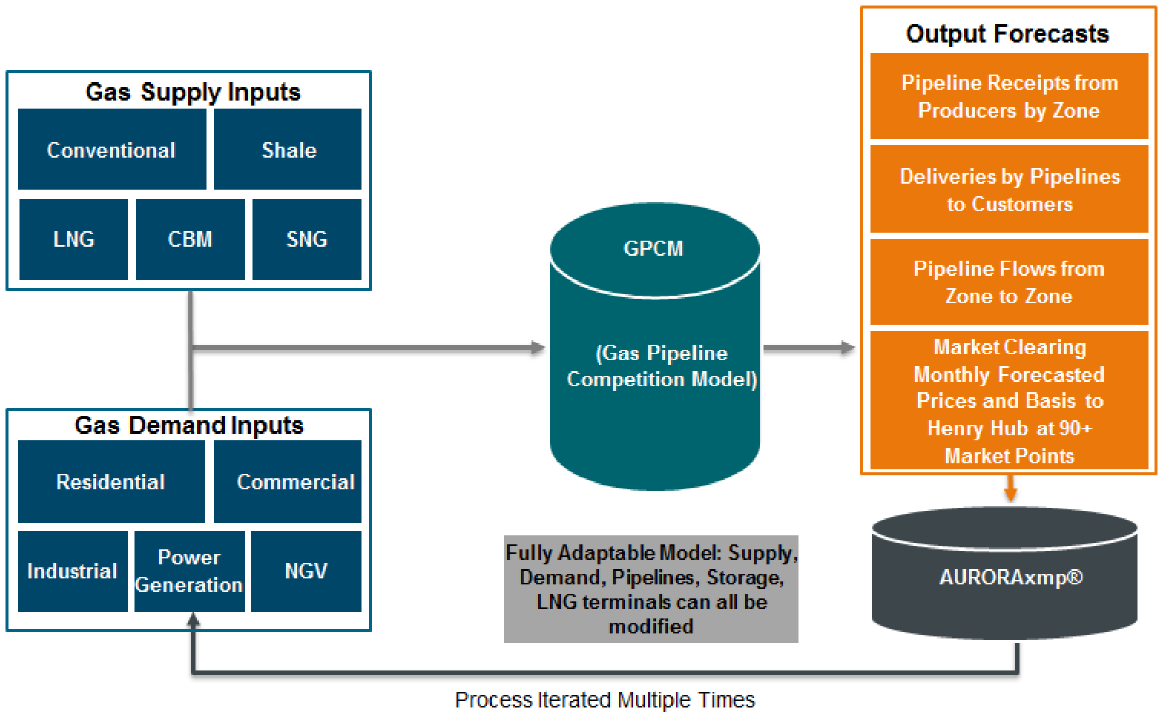
The output from GPCM® consists of the following types of items, which can be exported to an Excel spreadsheet for further analysis and reporting:

- Production and spot market prices by region
- Pipeline receipts from producers by zone
- Pipeline flows from zone to zone
- Transportation prices and discounting by pipeline and zone
- Transfers between pipelines at interconnects
- Injections into and withdrawals from storage
- Deliveries by pipelines to customers
- Gas supply available to each customer in each region
- Market clearing prices in each region

GPCM® Geography and Granularity

GPCM® covers the North American natural gas market, including the continental United States, Canada, and Mexico. GPCM® also contains a graphical display system to visually analyze interconnections, flows, and other output from the model. Demand forecasts can be manipulated by sector and by state. Supply sources can be manipulated by basin or play. Output data is provided on a monthly basis but can be aggregated up to annual averages. The forecasting horizon extends out to December 2040.

Figure A-1. GPCM® and Integration with Power Market Model (AURORAxmp®)



Source: Siemens

GPCM® Power-Gas Model Integration

The integration of the AURORAxmp® and GPCM® modeling frameworks is one of the cornerstones of Siemens's modeling. At a high level, the GPCM® modeling framework receives inputs from AURORAxmp® on current and expected power sector gas demand based on expected generation capacity additions, coal-gas switching, coal plant retirements, impacts of carbon regime etc. The AURORAxmp® model in turn receives gas pricing inputs based on the supply economics, pipeline expansion plans, and all natural gas consuming sectors of the economy, including power. The final "equilibrated level" is such that gas price levels and the implied power sector gas demand levels are consistent across both models.

It is important to note that initially Siemens develops each of its fundamental market forecasts for natural gas (GPCM®) and power (AURORAxmp®) independently. Once complete, these independent forecasts are then harmonized through the iterative feedback process. Monthly natural gas prices at the benchmark Henry Hub and 60+ major liquid natural gas trading hubs throughout North America developed in GPCM® are used as inputs to the AURORAxmp® model. The output from the power model is then segmented into monthly state level data on natural gas consumption in the power sector. This forecast is then used as an input to the natural gas model, by setting demand targets for power sector gas consumption and by setting the price elasticity of power sector gas demand to zero. When a new set of gas prices and basis forecasts have been computed, a full iteration has been completed. For the second and third iterations, a weighted average of previous iterations is used to dampen oscillations between cycles (for example, a low gas price would encourage high gas burn, which would

raise prices, which would lower gas burn, and so forth). Typically, after 3-4 iterations, the models are sufficiently calibrated such that further iterations are not needed.

It should be noted that prior to the harmonization efforts between GPCM® and AURORAxmp®, the gas model undergoes its own balancing with the supply assumptions. DrillingInfo's ProdCast® tool for natural gas production forecasting allows Siemens to input its own crude oil and natural gas price assumptions into the model, providing an iterative calibration opportunity to better refine the natural gas supply outlook. Also, at the macro-economic level, both GPCM® and AURORAxmp® follow internally consistent assumptions around GNP growth rate and the electrical sector demand tied to the GNP growth rate. The GPCM® model also has separate growth rates for the other sectors of the economy.

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AEE 11.0-214
10/18

Autoridad de Energía Eléctrica de Puerto Rico

SOLICITUD DE AUTORIZACIÓN A LA OFICINA DE GESTIÓN DE PROYECTOS E INNOVACIÓN PARA OTORGAR CONTRATOS DE SERVICIOS PROFESIONALES O COMPRADOS

Fecha de la solicitud 31 de octubre de 2019

Directorado que Solicita la Autorización Ejecutivo

Funcionario Autorizado del Directorado Edwin Barbosa Viera

Tipo de Contrato ____ **Servicios Profesionales** ✓ **Servicios Comprados**

Contrato ____ **Nuevo** ____ **Enmienda** ____ **Renovación**

Justificación y Breve Descripción del Contrato ____

La solicitud de esta autorización es para propósitos de asignar fondos al contrato 902-04-19, el cual provee para la adquisición de combustible gas natural, (Ecoeléctrica cogeneración) y (PREPA Costa Sur operación unidades 5 y 6)

Contratista Naturgy Aprovisionamientos S.A.

Cuantía Solicitada $9,001,000,000.00

Partida Presupuestaria (Certificación de Fondos) 1-2321-23125-000-000

Naturaleza de los Fondos (Estatales, Federales, Mixtos, o de la Corporación Pública) Corp. Pública

Fondos Rembolsables Sí ____ **No** ✓

Vigencia del Contrato: Desde su otorgamiento hasta 01/01/2020 hasta 12/31/2032

¿La agencia tiene algún otro contrato vigente con ese contratista? Sí ✓ **No** ____

De tener algún otro contrato, especificar:

Número: 902-05-12 **Cuantía:** ____ **Partida Presupuestaria:** 1-2321-23215-000-000

Vigencia: 12/31/2020 **(día/mes/año)** **Tipo de Contrato: Servicios Profesionales** ____ **Servicios Comprados** ✓

Cuantía del Contrato Original ____

Cuantía Total de las Enmiendas Autorizadas Previamente ____

Total Autorizado (incluyendo enmiendas) ____

Certifico que este(a) ✓ **Contrato/** ____ **Enmienda a Contrato, cumple y es consistente con el Plan Fiscal de la Autoridad de Energía Eléctrica de Puerto Rico. En San Juan, Puerto Rico, hoy** ____ **de** ____ **de** ____.

Fernando M. Padilla Padilla

Administrador de Restructuración y Asuntos Fiscales
Oficina de Gestión de Proyectos e Innovación

Fecha: ____

Government of Puerto Rico
Puerto Rico Electric Power Authority

JRSP - SECRETARIA
NEGOCIADO DE ENERGIA
DE PUERTO RICO
2019 NOV -5 AM 10: 35

November 4, 2019

CONFIDENTIAL

Mr. Edison Avilés-Deliz, Chairman
Puerto Rico Energy Bureau
World Plaza Building, 268 Muñoz Rivera Ave.
Plaza Level, Suite 202
San Juan, PR 00918

Dear Mr. Chairman:

Re: Request for Approval of Amended and Restated Power Purchase and Operating Agreement with EcoEléctrica and Natural Gas Sale and Purchase Agreement with Naturgy; Request for Confidential Treatment of this Letter and Accompanying Attachments

The Puerto Rico Electric Power Authority ("PREPA") respectfully submits to the Puerto Rico Energy Bureau ("PREB") the attached Amended and Restated Power Purchase and Operating Agreement between EcoEléctrica, L.P. and the Puerto Rico Electric Power Authority (the "ECO PPOA") (**Attachment 1**) and the Amended and Restated Natural Gas Sale and Purchase Agreement between Naturgy Aprovisionamientos S.A. and the Puerto Rico Electric Power Authority (the "Naturgy GSPA" (**Attachment 2**) and, together with the ECO PPOA, the "Agreements"). PREPA asks PREB to review and approve the Agreements pursuant to Section 7.1 of Regulation 8815.[1] Moreover, for reasons developed in **Part V** below, PREPA asks that PREB afford this letter, the ECO PPOA, the Naturgy GSPA and the Siemens analysis included as **Attachment 4** as Confidential in that they contain information protected under Puerto Rico law.

Representatives of PREPA, EcoEléctrica, L.P. ("ECO") and Naturgy Aprovisionamientos S.A. ("Naturgy") concluded their negotiation and documentation of the Agreements earlier this month. The PREPA Governing Board has authorized the submission of these Agreements to the PREB for its approval by Resolution 4745, dated October 29, 2019 (**Attachment 3**).

Chief Executive Officer
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[1] *Joint Regulation for the Procurement, Evaluation, Selection, Negotiation and Award of Contracts for the Purchase of Energy and the Procurement, Evaluation, Selection, Negotiation and Award Process for the Modernization of the Generation Fleet* (Oct. 11, 2016) ("Regulation 8815").

The ECO PPOA provides for the supply of capacity, energy and ancillary services from EcoEléctrica's existing 543 MW combined-cycle, natural gas-fired cogeneration facility located in Peñuelas (the "ECO Facility"). The Naturgy GSPA provides for the supply of natural gas to Units 5 and 6 of PREPA's 820 MW Costa Sur generating facility located adjacent to the ECO Facility (the "Costa Sur Units"), as well as to the ECO Facility. The Agreements incorporate more favorable pricing and other terms for PREPA and ratepayers in Puerto Rico than the agreements they will replace, and they will secure for Puerto Rico important sources of reliable electric capacity and energy that will support and advance Puerto Rico's energy policy goals as articulated in Act No. 17 of April 11, 2019, the *Puerto Rico Energy Public Policy Act* ("Act 17-2019").

The ECO PPOA and the Naturgy GSPA, once approved by the PREB, the Public-Private Partnerships Authority ("P3") and the Financial Oversight and Management Board for Puerto Rico ("FOMB") and executed by the parties, would replace the existing *Power Purchase and Operating Agreement* between PREPA and ECO dated as of March 10, 1995, as amended, and the *Natural Gas Sale and Purchase Agreement* between PREPA and Naturgy dated as of March 28, 2012, as amended.

This letter discusses the commercial rationale supporting the ECO PPOA and the Naturgy GSPA, each Agreement's key features and the main risks that each Agreement addresses and mitigates. This letter also confirms that the negotiation of the Agreements was conducted in accordance with the requirements of applicable Puerto Rico law and regulations.

In compliance with PREB's directions, PREPA has evaluated how the pricing and other commercial terms reflected in the ECO PPOA and the Naturgy GSPA might affect the analyses incorporated in its Integrated Resource Plan ("IRP") and the recommendations reflected in PREPA's Action Plan. As described in **Part IV** below, PREPA's IRP consultant, Siemens, has incorporated in new Aurora model runs the revised capacity payment and certain other commercial provisions established in the ECO PPOA, as well as the revised natural gas pricing and resulting price of electric energy produced in the ECO Facility that will apply with execution of the Naturgy GSPA. These new model runs show that the ECO PPOA (as amended and restated from the PPOA assumed in earlier IRP model runs, and assuming the pricing of natural gas as provided in the Naturgy GSPA) to be substantially more economical under the IRP's Scenario 4 than the alternative of constructing a new combined cycle combustion turbine generating facility sited at Costa Sur. See Attachment 4. *PREPA and Siemens personnel are willing to provide the relevant files and worksheets to PREB, and are available and eager to discuss with PREB members and consultants the assumptions employed in and the results of these new model runs. We invite you to inform us if you believe such discussions would be useful to the Bureau.*

Mr. Edison Avilés-Deliz
November 4, 2019
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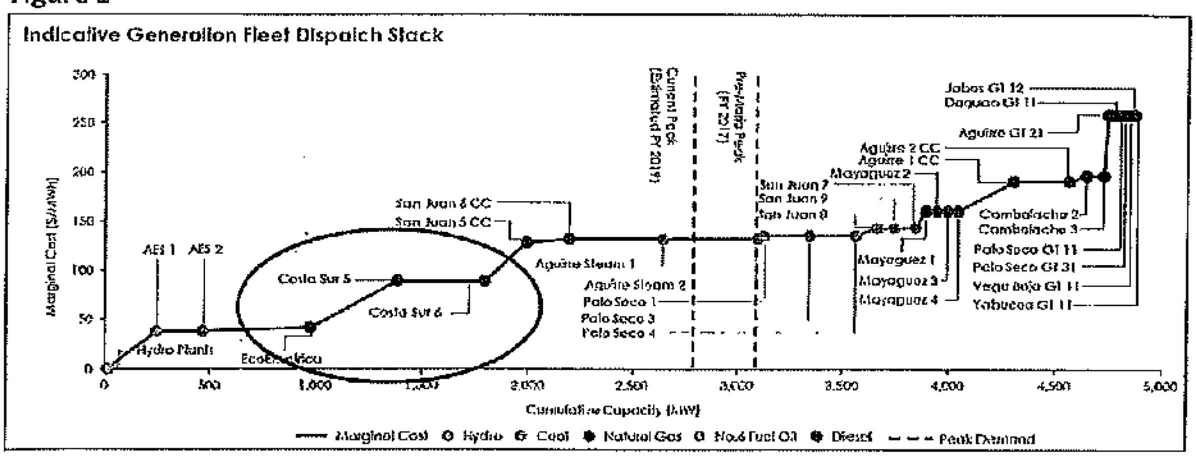
We conclude with a request that the PREB approve the ECO PPOA and the Naturgy GSPA as being in the best interest of the electricity consumers of Puerto Rico.

I. Commercial Rationale for Entering into the ECO PPOA and the Naturgy GSPA

PREPA is responsible for supplying secure and reliable electric power to ratepayers in Puerto Rico at the lowest cost possible in both the short and long term, consistent with the guidelines established by PREPA's Fiscal Plan (which, among other things, requires PREPA to achieve $80 million in aggregate savings through renegotiation of the existing EcoEléctrica PPOA and the *Power Purchase and Operating Agreement between AES Puerto Rico, LP and PREPA* (the "AES PPOA")), and consistent with the IRP which is currently before the PREB in draft form. The ECO Facility and the Costa Sur Units are critical to PREPA's provision of supplies of electric power on a reliable basis; together, they provide providing almost 40% of the electricity PREPA distributes on the island at some of the lowest cost per kWh of any generation source available, as shown in **Figure 1** below.

Figure 1



Through the ECO Facility ECO, a company jointly owned by Naturgy, ENGIE S.A. and Mitsui & Co. (i) offers one of PREPA's most reliable sources of generation, and (ii) owns the only currently active liquified natural gas ("LNG") import terminal and LNG storage facility in Puerto Rico. The Costa Sur Units rely on this terminal for the receipt, storage and conversion of LNG and the supply of natural gas. Naturgy, the 50% shareholder in ECO, controls (through a Tolling Services Agreement with ECO) the entire existing capacity of the Peñuelas LNG receiving terminal to receive, store and vaporize LNG and therefore controls the delivery of the resulting natural gas

for generation. EcoEléctrica currently provides baseload energy to Puerto Rico through the ECO Facility at the lowest cost per kWh of any generation source available to PREPA other than the AES Puerto Rico, LP ("AES") coal-fired generating facility. Together with the Costa Sur Units, the ECO Facility currently produces over 40% of Puerto Rico's electric energy. Naturgy, as a main shareholder in EcoEléctrica, controls (through a Tolling Services Agreement) the entire existing capacity of that terminal to receive, store and vaporize LNG for the delivery of natural gas used to fuel the ECO Facility and the Costa Sur Units. Thus, PREPA views EcoEléctrica's facilities as critically important for the supply of both generation and fuel for generation in Puerto Rico.

Against this background, PREPA began direct negotiations with ECO and Naturgy – the sole source of natural gas delivered to the ECO Facility and Costa Sur Units – in late 2018. PREPA's goal was to achieve, as nearly as possible, the savings objectives of the Fiscal Plan and to position itself to secure access to critically important fossil generating resources in a manner consistent with the IRP now before the PREB. PREPA engaged the assistance of Sargent & Lundy ("S&L"), King & Spalding LLP and Díaz & Vázquez ("D&V") to support PREPA's negotiation efforts, and socialized the planned approach to contracting with ECO and Naturgy among FOMB, PREB and P3 to facilitate the approval process.[2]

The terms PREPA has negotiated in the ECO PPOA and the Naturgy GSPA will enhance the flexibility, reliability, and resilience of Puerto Rico's electric grid. As important, the Agreements will yield immediate savings for Puerto Rico electric ratepayers of $122.4 million per year, according to estimates prepared by S&L. These savings exceed those the FOMB has targeted for the renegotiation of both of PREPA's major PPOAs, even before PREPA has commenced efforts to renegotiate the AES PPOA.

The restructured arrangements with ECO and Naturgy contemplate that PREPA will secure the natural gas required to supply the ECO Facility and Costa Sur Units under the Naturgy GSPA. That agreement has been substantially amended to provide PREPA improved pricing terms and greater nomination flexibility than those available under the currently effective agreement through which it obtains gas for the Costa Sur Units. The ECO PPOA likewise has been

[2] P3 released PREPA to continue with the negotiation of the ECO PPOA and the Naturgy GSPA without commencing a competitive procurement process, on the condition that PREPA include appropriate contract assignment/transfer rights to accommodate the transformation of Puerto Rico's electricity sector and the possible replacement of PREPA as contract counterparty (which PREPA did). Attorneys from D&V have confirmed that if Naturgy holds the exclusive rights to the regasification facility, then the negotiation of the ECO PPOA and the Naturgy GSPA could fit within an exception to the competitive bidding process under the "one supply source" exception found in PREPA's Organic Act.

substantially amended, so that it now takes the form of a "tolling agreement" through which PREPA will supply the natural gas to be converted to electric energy in the ECO Facility.

PREPA has negotiated in the ECO PPOA a reduction in the Capacity Payment relative to the current EcoEléctrica PPOA's Capacity Payment that will save approximately $108 million annually. This amount is partially offset by an increase in the fuel cost which PREPA will bear under the Naturgy GSPA; nevertheless, the net PPOA price reduction, according to S&L, is approximately $56.3 million annually. Viewed collectively, the Agreements will immediately lower the cost of power from the ECO Facility, already one of Puerto Rico's lowest cost generators, by approximately 1.5 cents per kWh.

Additional savings are possible. Under the existing EcoEléctrica PPOA, if PREPA dispatches EcoEléctrica at capacity factors higher than 76%, PREPA must pay a higher fuel cost (a fuel "spot price") for generation above the 76% threshold. For this reason, at times when the ECO Facility's capacity factor would increase above 76%, PREPA sometimes chooses to dispatch other facilities instead of EcoEléctrica on the basis of economics. The ECO PPOA removes this fuel pricing step feature, which will allow PREPA to dispatch the ECO Facility above a 76% capacity factor without having to pay the increased fuel "spot price." S&L estimates this will save PREPA approximately $66.1 million annually in fuel costs derived from reducing dispatch of other, more expensive, facilities in favor of dispatching the ECO Facility at a higher capacity factor.

One other feature of the ECO PPOA warrants emphasis. ECO has agreed in the ECO PPOA to increase the capacity sold to PREPA from 507 MW to 530 MW. Naturgy has also agreed to update the structure of the existing GSPA to allow for this increase in generation with significantly increased flexibility to PREPA in take-or-pay obligations. Overall, this flexibility will give PREPA the ability to reduce the dispatch of its more expensive, inefficient generators that burn both diesel and bunker fuel oil, resulting both in fuel cost savings and reduced air emissions.

II. Overview of the Major Provisions of the ECO PPOA and Naturgy GSPA

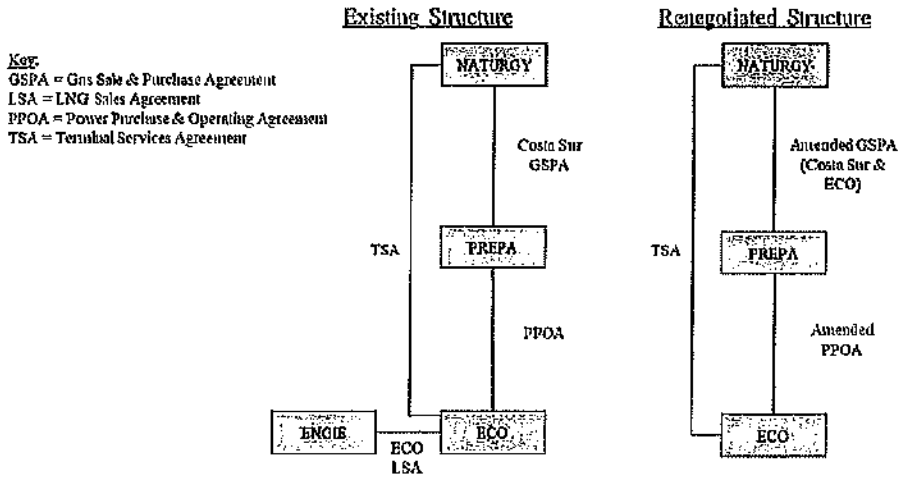
With the execution of the ECO PPOA and the Naturgy GSPA, PREPA will:

- restructure the power purchase arrangement under which ECO currently supplies electric capacity and energy to PREPA and the fuel supply arrangements under which Naturgy currently supplies natural gas to the Costa Sur Units, such that PREPA contracts with Naturgy for, and nominates, natural gas for delivery to the Costa Sur Units and the ECO Facility, as shown in **Figure 2** below;

- convert the ECO PPOA into a tolling arrangement for the conversion of natural gas into electricity, which facilitates an eventual move toward an aggregated, island-wide LNG / gas procurement strategy that should help to achieve the most competitive pricing terms for LNG delivered to Puerto Rico; and

- enable the ECO Facility to transition from base load production, operating during all hours of the day, to a dual mode of operation through which, following the scale-up of intermittent renewables in Puerto Rico's generation mix as contemplated by Act 17-2019 and the IRP, the ECO Facility will provide (i) during day-time hours, cycling and ancillary services as required to stabilize / balance the grid, and (ii) during night time hours, base load production.

Figure 2



These structural changes, and other negotiated terms, will deliver a number of benefits to PREPA and Puerto Rico.

A. Key Features of the ECO PPOA

To implement the structural changes and achieve the savings described above, PREPA negotiated several important changes to the ECO PPOA relative to the existing EcoEléctrica agreement. The following table briefly summarizes the most significant of these changes:

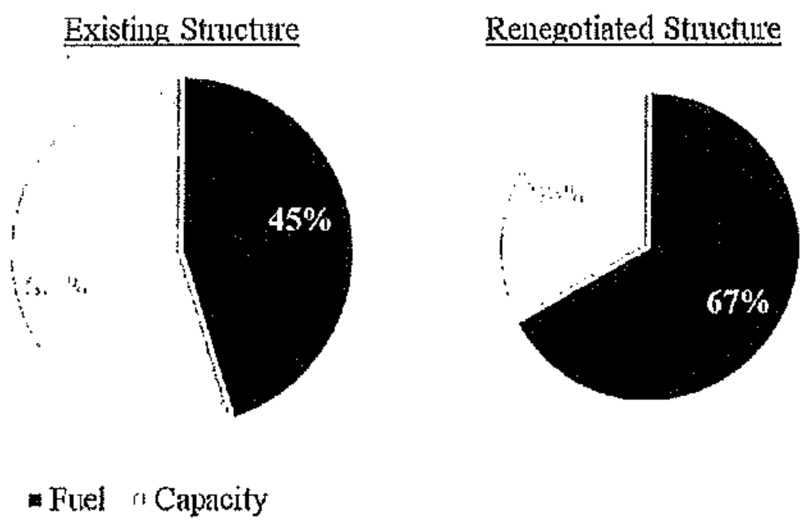
	Existing EcoEléctrica PPOA	Renegotiated ECO PPOA
Expiration of Supply Term	March 2022	September 2032
Dependable Capacity	507 MW	530 MW
Responsibility for Fuel Procurement	ECO	PREPA
Commercial Model	Capacity Payment + Energy Payment (inclusive of fuel pass-through)	Capacity Payment
Capacity Payment	Approximately $230M per year at 507 MW (corresponding to $241M per year at 530 MW)	Approximately $128M per year at 530 MW (subject to an availability adjustment)
Energy Payment	Average of 5.5 center/kWh per year; increase to 10+ cents/kWh >76% capacity factor	N/A (equivalent payment under GSPA estimated at 7.1 cents/kWh)
Availability Adjustment	Penalty and bonus for low and high availability	Equivalent structure, with a higher bonus potential. Bonus is 0% at 93% EAF* and 29% at 95% EAF or above. Bonus increases linearly between 93% and 95% EAF
Dispatch Limits	Between 54%-76% of Dependable Capacity	Between 54%-100% of Dependable Capacity
Maximum Start-Ups	Limit of 50 per unit per year	Limit of 100 per unit per year
Start-Up Costs	PREPA pays ECO's start-up costs until the units synchronize to the grid	Terms remain unchanged, other than ECO reimburses PREPA for fuel costs associated with start-up

*Equivalent Availability Factor

PREPA achieved several key objectives with these and other changes, including:

1. **Cycling / Ancillary Services Mode** – The ECO Facility has historically operated as a base load generator. The IRP and Puerto Rico law, however, envision a significant increase in renewable energy generation in the coming years, which would require more flexible operations from the ECO Facility. The renegotiated ECO PPOA allows PREPA to change the mode of operation of the ECO Facility to cycling and supply ancillary services during daylight hours, as more solar generation comes onto the grid. It includes an allowance of 100 shut-downs / start-ups of each ECO Facility unit per year, and provides for the supply of reactive supply and voltage control services, regulation and frequency response services, energy imbalance services, spinning reserve and supplemental spinning reserve, in each case as dispatched by PREPA. S&L estimates that, because fuel expenses will likely make up a higher percentage of the total payments to ECO/Naturgy under the combination of the ECO PPOA and the Naturgy GSPA (see **Figure 3** below), over time operation in the more flexible mode the ECO PPOA will permit, and the corresponding reduction in the quantity of energy supplied by ECO, could significantly reduce PREPA's fuel expenses.

Figure 3



2. **Added Incentive for High Availability** – To further incentivize ECO to maximize the availability the ECO Facility, PREPA has negotiated an increased availability bonus, with reasonable limitations to avoid excessive compensation. These limitations include a cap on the three-month rolling average bonus at 15% above the Capacity Payment for 2020, and a fixed planned maintenance schedule thereafter, to prevent ECO from gaming the bonus mechanism. Anticipating that ECO will be able to make available generation capacity in excess of 530 MW, PREPA also negotiated a peak energy tariff just above three cents/kWh for the volumes of energy that PREPA takes between the Dependable Capacity level of 530 MW and 543 MW. The fixed price allows the parties to plan on utilizing such energy, and the additional 13 MW, if so utilized, can essentially serve as a second small power plant offering a price below even the price currently paid for energy from the AES plant.

3. **Guaranteed Efficiency of Energy Conversion** – The new energy conversion / tolling structure of the ECO PPOA requires efficient conversion into electricity of the natural gas PREPA has contracted with Naturgy to deliver to ECO. With this in mind, PREPA developed a system of heat rate testing and guarantees to help ensure that PREPA does not overpay for ECO's gas consumption and that ECO has an incentivize to maintain the ECO Facility's efficiency. Under this arrangement, ECO bears the cost of excess gas if it consumes more gas than it should for a given energy output, and receives full value of any savings if it consumes less gas than it should, in each case based on a guaranteed heat rate.

4. **Reduced Payments During Severe Weather Events** – The original EcoEléctrica PPOA required PREPA to pay the capacity payment so long as ECO remained available. This led to a dispute between ECO and PREPA in the wake of Hurricane María as to whether PREPA was obligated to make the capacity payment for an approximately one-month period in which the ECO Facility could generate, but the PREPA grid system had not yet recovered. PREPA has negotiated a 30-day Force Majeure exception to such capacity payment obligation going forward, to the extent that a disruption limiting the ability to take power from the ECO Facility is caused by hurricanes or other severe atmospheric disturbances ("Grid Force Majeure Events").

5. **Enhanced Linkage between the Naturgy GSPA and ECO PPOA** – Given the relationship of Naturgy with ECO, and the co-dependence of the LNG Terminal and the ECO Facility, PREPA took steps to ensure that neither counterparty's actions could leave PREPA at a disadvantage *vis-à-vis* the other. These steps included, for example, granting PREPA, subject to certain conditions, (i) the option to purchase the LNG terminal and the ECO

Facility if ECO abandons the operation of either one, (ii) the right to reductions in the Capacity Payment to the extent the ECO Facility is not capable of providing service due to outages affecting the LNG terminal, and (iii) the right to terminate the PPOA if the tolling agreement with Naturgy terminates due to an ECO default.

6. **Additional Fuel Savings Resulting from the Elimination of an Oil Price Hedge** – The existing GSPA for Costa Sur has a built-in pricing hedge to oil. This provision is not included in the proposed Naturgy GSPA, and therefore the price of natural gas to be consumed in the ECO Facility will not reflect any costs relating to the maintenance of an oil price hedge. Given that natural gas prices are forecasted to remain much lower than oil prices over the next decade, S&L estimates that removing the hedge to oil and reducing the adder fee will result in average savings for PREPA of approximately $29.1 million per year for the Costa Sur Units (see item C.1 below). These savings are not included in the headline savings value provided in Section I above.

B. Main ECO PPOA Risks

PREPA remains exposed to certain risks under the ECO PPOA. These include:

1. **Capacity Payment Liability Risk** – The renegotiated PPOA exposes PREPA to a number of risks relating to its liability to make Capacity Payments. As the PREB will appreciate, it is standard in the electric utility industry for purchasers of capacity, energy and ancillary services under power purchase agreements to compensate power producers for their commitment to make capacity available. PREPA's undertaking to make Capacity Payments under the ECO PPOA are entirely consistent with this industry practice; moreover, PREPA has sought in the ECO PPOA to mitigate the risk associated with this unavoidable undertaking. **Annex A** describes the manner in which these risks are allocated between PREPA and ECO in the ECO PPOA.

2. **Risks to Security of Supply** – ECO's LNG terminal facilities constitute infrastructure that is critical to the supply of electric power to the island of Puerto Rico. As long as these facilities remain in the hands of a private party, PREPA and Puerto Rico ratepayers will face some risk that the party owning or controlling the LNG terminal facilities might take actions that could adversely affect the availability or price of LNG terminal services and hence the reliability and price of electric energy. So, for example, PREPA remains exposed to the risk under the ECO PPOA that ECO might (i) abandon or permanently shut down the ECO Facility or the LNG terminal, or (ii) default under and/or terminate the tolling

agreement with Naturgy. In such an event, PREPA would likely experience prolonged interruption of operations at the ECO Facility and the Costa Sur Units, and consequently the supply of power to ratepayers could either be interrupted or rendered much costlier. While this risk is inherent in the manner in which the LNG terminal and ECO Facility are owned, the PPOA partially mitigates this risk by providing PREPA with the option to purchase the LNG terminal and/or ECO Facility in defined circumstances for a price to be determined in accordance with the PPOA.

C. Key Features of the Naturgy GSPA

The table appearing below summarizes the major changes in the Naturgy GSPA relative to the arrangement under which natural gas is currently supplied to the Costa Sur Units:

	Existing GSPA	Renegotiated GSPA
Term	December 2020	September 2032
Facilities Supplied	Costa Sur Units 5 and 6	Costa Sur Units 5 and 6 and ECO Facility (and potentially others)
Pricing Hedge	Hedge to No. 6 fuel oil	Market based price pegged to the New York Mercantile Exchange's Henry Hub natural gas futures contracts price ("HH"), with a fixed, but declining, premium.

	Existing GSPA	Renegotiated GSPA
Pricing Formula	<u>Price per MMBtu</u> The lesser of: • 0.97 * (No. 6 Fuel Oil Price + $1.29), and • 0.97 * [50% * (No. 6 Fuel Oil Price + $1.125) + 50% * (115% HH + $5.95)], where the No. 6 Fuel Oil Price is converted from $/bbl to $/MMBtu by dividing by 6.03	<u>Price per MMBtu</u> • Conditions precedent date until Dec. 31, 2020: 115% x HH + $5.80 • January 1, 2021 until Dec. 31, 2021: 115% x HH + $5.70 • January 1, 2022 until Dec. 31, 2022: 115% x HH + $5.60 • January 1, 2023 until Sept. 2032: 115% x HH + $5.50 (Potential price reductions up to $1 per MMBtu for Jones Act appeal or suspension)
Minimum Annual Contract Quantity	45 TBtu (Costa Sur only)	55 Tbtu (Costa Sur and ECO), subject to further reductions described below
Maximum Annual Contract Quantity	72 Tbtu	106 Tbtu (unless a reduction of the minimum annual contract quantity occurs, in which case the maximum will be 120% of the new minimum annual contract quantity)
Take-or-Pay	75% of the monthly minimum quantity, 90% of the quarterly minimum quantity, and an overall take-or-pay ("TOP") contract quantity. TOP amounts payable at 90% of the relevant contract price	75% of the monthly minimum quantity and 90% of the quarterly minimum quantity, but no overall contract quantity. TOP amounts payable at 90% of the relevant contract price

PREPA achieved several key objectives with these and other changes, including:

1. **Savings Resulting from the Elimination of an Oil Price Hedge** – As noted in item A.6 above, the existing GSPA for Costa Sur has a built-in pricing hedge to oil. This provision is not included in the proposed Naturgy GSPA. S&L estimates that removing the hedge to oil and reducing the adder fee will result in average savings for PREPA of approximately

$29.1 million per year for the Costa Sur Units. These savings, which are based on fuel commodity price forecasts, are expected to be modest over the first five years (averaging approximately $10 million per year), but will increase in the future as the spread between natural gas and oil prices widens.

2. **Reduced Take-or-Pay Risk** – Under the existing transaction structure, as shown in **Figure 2** above, PREPA faces take-or-pay risk under the GSPA for the Costa Sur Units if those units experience an outage that reduces PREPA's natural gas offtake below 27 Tbtu/year, and also faces take-or-pay risk under the PPOA with EcoEléctrica, which indirectly passes through such risk from the ECO LNG sales agreement with Engie, to the extent PREPA cannot take electricity from the ECO Facility. The renegotiated Naturgy GSPA, also shown in **Figure 2**, allows for significantly increased flexibility for PREPA in terms of take-or-pay obligations. Under the Naturgy GSPA, PREPA gains the ability to (i) receive gas at either the ECO Facility or Costa Sur Units, depending on availability, (ii) redirect LNG cargoes under the Naturgy GSPA to other facilities around the island, (iii) receive full relief from take-or-pay liability to the extent an outage at the Costa Sur Units or ECO Facility prevents natural gas offtake, and (iv) with six months' notice, reduce the overall take-or-pay commitment for natural gas as follows:

    a. if PREPA retires one or both of the Costa Sur Units, PREPA may reduce the minimum annual quantity from 55 Tbtu to as low as 19 Tbtu;

    b. if, after January 1, 2024, peak electricity demand in Puerto Rico falls below 2,300 megawatts, PREPA may reduce the minimum annual quantity from 55 Tbtu to as low as 19 Tbtu;

    c. if, after January 1, 2024, the proportion of renewable generation sources available in Puerto Rico exceeds fifteen percent (15%) of the total power generated by sources connected to the grid system, PREPA may reduce the minimum annual quantity from 55 Tbtu to as low as 19 Tbtu;

    d. if ECO defaults under the PPOA, and that agreement is terminated, PREPA may reduce the minimum annual quantity from 55 Tbtu to as low as 0 Tbtu; and

    e. PREPA also has a general right to reduce the minimum annual contract quantity in accordance with criteria which PREPA, in its reasonable judgment,

determines are consistent with the maintenance of a reliable electric system operation and its economic dispatch program.

PREPA may, in its discretion, increase the minimum annual contract quantity specified in the Naturgy GSPA up to 55 Tbtu, but may not thereafter reduce such quantity again. Each of these options functions independently, and PREPA could potentially exercise all three at different times during the agreement term.

3. **Increased Quantity Flexibility** – PREPA negotiated significant flexibility to increase or decrease the quantity of natural gas it purchases from Naturgy between a maximum of 106 Tbtu and a minimum of 55 Tbtu (such maximum and minimum requirements, the "Base Case"). PREPA has further flexibility to adjust the volumes it purchases under the Base Case as it may reduce the minimum required amount for any (A) scheduled maintenance, (B) forced outages, (C) routine maintenance, (D) unit limitations (limitation on other infrastructure that prohibits the Costa Sur Units or the ECO Facility to generate at maximum capacity), I environmental testing requirements of PREPA, or (F) for scheduled maintenance by PREPA.

4. **Increased Delivery Location Flexibility** – Under the Naturgy GSPA, PREPA negotiated flexibility to add new delivery points. This will allow PREPA to purchase natural gas at the agreed contract price, or otherwise satisfy its take-or-pay obligations and make deliveries of natural gas to locations other than the two contemplated delivery points. The GSPA permits PREPA to request that Naturgy include as a new delivery point any LNG receiving facility that is a floating storage and regasification unit ("FSRU") capable of receiving cargoes from vessels having LNG capacity of more than 125,000 m^3. Upon such a request, Naturgy must study the relevant compatibility requirements, consistent with international standards, to determine if it is capable of making a delivery to such new FSRU. Further, if smaller scale LNG receiving facilities are constructed in Puerto Rico, Naturgy will also review whether it is able to make deliveries to such facilities so that they may be utilized under the GSPA as additional delivery points.

5. **Improved Liquidated Damages Regime for Shortfalls** – In an effort to protect PREPA against Naturgy's failure to deliver required volumes under the GSPA, the GSPA establishes certain pre-determined damages (unless such delivery was excused for force majeure or reasons attributable to PREPA). The GSPA bifurcates the damages available to PREPA for Naturgy's failure to deliver quantities of natural gas scheduled to the Costa

Sur Units versus quantities scheduled for delivery at the ECO delivery point.[3] For Naturgy's failure to deliver natural gas at Costa Sur, Naturgy would pay PREPA a liquidated damages amount of 15% of the relevant contract price multiplied by relevant shortfall quantity. If, prior to the date of any assignment under the Naturgy GSPA to a Non-Commonwealth Entity, Naturgy fails to deliver the required amount of natural gas at the ECO delivery point, Naturgy must reimburse PREPA for (i) the excess capacity payment that PREPA must continue to make under the PPOA and (ii) all costs associated with the purchase of back-up fuel for the generation of electricity. If, after the date of any assignment under the GSPA to a Non-Commonwealth Entity, Naturgy fails to deliver the required amount of natural gas at the ECO delivery point, Naturgy would be required to pay PREPA a liquidated damages amount of 15% of the relevant contract price multiplied by the relevant shortfall quantity.

6. **Protections Against Parasitic Use of Natural Gas** – The original GSPA did not acknowledge that ECO would use natural gas owned by PREPA for the operation of the LNG Terminal, because delivery under that agreement only went to Costa Sur. The renegotiated Naturgy GSPA establishes a mechanism that compensates PREPA for ECO's / Naturgy's use of PREPA's natural gas.

7. **Force Majeure Relief for Grid System Outages** – While the original GSPA makes Force Majeure relief available to both Naturgy and PREPA, the renegotiated Naturgy GSPA also grants PREPA the right to Force Majeure relief for serious accidental damage to, or any loss, inaccessibility, incapacity, or inoperability of, the grid system. This mitigates many of the most likely events for which PREPA could have faced take-or-pay liability.

D. Main Naturgy GSPA Risks

The renegotiated Naturgy GSPA exposes PREPA to certain risks relating to the potential for supply interruptions. **Annex B** describes the allocation of those risks between PREPA and Naturgy. The allocation of risks is consistent with the allocation generally found in agreements for the supply of natural gas derived from LNG for power generation purposes.

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[3] The ECO delivery point is established as the location of the metering equipment situated downstream from the connection of the boil-off gas pipe to the main pipeline where natural gas enters the ECO Facility.

III. Compliance with Applicable Legal Requirements

The ECO PPOA amends and restates a PPOA between EcoEléctrica and PREPA that has been in place since 1995 and was the result of a competitive procurement process. As it has been amended, the ECO PPOA, originally a conventional power purchase agreement, has been converted into a "tolling agreement" under which PREPA will supply natural gas to the ECO Facility and ECO will maintain the capacity to convert and, in accordance with dispatch instructions from PREPA, will convert that natural gas into electric energy. The Naturgy GSPA amends and restates a natural gas supply agreement that was executed in 2012 to support deliveries of natural gas to PREPA's existing Costa Sur Units 5 and 6. As amended, the scope of the original gas supply agreement will be substantially enlarged to cover purchases of natural gas to be consumed in the generation of electric energy in the ECO Facility. Consequently, with the execution of the Naturgy GSPA, Naturgy will become a new supplier of natural gas to PREPA with respect to the ECO Facility, and given this the Naturgy GSPA can be considered a new contractual obligation for PREPA.

The Naturgy GSPA was not the result of a competitive bidding process. Such a process was not, however, required under the applicable provisions of PREPA's enabling act, Act No. 83 of May 2, 1941, the *Puerto Rico Electric Power Authority Act*, as amended ("Act 83-1941"). That act authorizes PREPA "[t]o make contracts and to execute all instruments necessary or convenient in the exercise of any of its powers," but generally requires PREPA to seek and obtain competitive bids before awarding contracts. There is, however, and exception to this requirement (the "sole source" exception) available in circumstances in which "there is only one supply source." Act No. 83-1941, Section 15(2)(d). Such circumstances exist in the case of Naturgy, which owns the only currently active LNG import terminal and LNG storage facility on the south shore of Puerto Rico and (through a Tolling Services Agreement with ECO) controls the entire existing capacity of this LNG import terminal to receive and vaporize LNG for the delivery of natural gas for power generation purposes. Given this, Naturgy has a *de facto* monopoly over the supply of gas into the southern part of the island and, thus, the sole source exception set forth in paragraph (d) of Section 15(2) of PREPA's enabling act applies.

PREPA proposes to enter into the ECO PPOA and the Naturgy GSPA for public purposes (the procurement of electric generating capacity and energy and of the fuel required to produce electric energy that will be transmitted and distributed to the people of Puerto Rico). This is a lawful public purpose within the meaning of Article VI, Section 9 of the Puerto Rico Constitution, and the contract should, therefore, be enforceable under Puerto Rico law. Under Act No. 120 of June 21, 2018 (the *Puerto Rico Electric System Transformation Act*) ("Act 120-2018"), P3 has been

empowered to manage the process through which what it designates as "PREPA Transactions" are to be concluded. *See also "Regulation for the Procurement, Evaluation, Selection, Negotiation and Award of Partnership Contracts and Sale Contracts for the Transformation of the Electric System Under Act No. 120-2018, as amended"* (March 8, 2019). P3 has concluded that the transactions to be effected through the ECO PPOA and the Naturgy GSPA qualify as "PREPA Transactions," and accordingly final P3 approval will be required in order for the Agreements to be enforceable. P3 has conditionally approved the transactions envisioned by the ECO PPOA and the Naturgy GSPA, subject to its review of the final versions of these Agreements. PREPA has made a submission to P3 similar to the one being made with this letter, and P3's response and approval are pending.

Pursuant to Section 204(b)(2) of the *Puerto Rico Oversight, Management, and Economic Stability Act*, 48 U.S.C. §§ 2101, *et seq.* ("PROMESA"), the FOMB has implemented a contract review policy that requires "[a]ll contracts or series of related contracts, inclusive of any amendments, modifications, or extensions, with an aggregate expected value of $10 million or more, including any professional advisory or personal services contracts, [to] be submitted to the FOMB for its approval before execution." *FOMB Review of Contracts*, November 6, 2017 as modified on July 3, 2018. The transactions contemplated by the ECO PPOA and the Naturgy GSPA are contemplated in PREPA's Fiscal Plan; FOMB's contract review policy is applicable to them given that the value of each exceeds the $10 million threshold. Consequently, FOMB approval is necessary prior to contract execution. PREPA has sought this approval, and made a submission similar to the one being made with this letter, and the FOMB's review and approval are pending.

IV. Reconciliation of the Terms of the ECO PPOA with Assumptions Incorporated in the IRP

As the PREB is aware, PREPA's IRP adversary proceeding filed in Docket No. CEPR-AP-2018-0001, *In Re: Review of the Puerto Rico Electric Power Authority Integrated Resource Plan*, envisions the replacement of the ECO Facility and the existing Peñuelas LNG receiving terminal with a new FSRU and combined cycle gas-fired generation facility in the same geographical area by 2025 (the "Replacement CCGT Project"). In PREPA's view, the terms it has secured through negotiation of the ECO PPOA and the Naturgy GSPA make the continued operation of the ECO Facility and related Peñuelas LNG receiving terminal a substantially more attractive option than the Replacement CCGT Project.

PREPA has reached this conclusion for several reasons. The ECO Facility and Naturgy, as LNG/natural gas supplier, have proven track records of reliable and cost-effective performance. They represent, from PREPA's perspective, the proverbial "bird in the hand." By contrast, the Replacement CCGT Project would entail significant execution risk and thus considerable uncertainty, given (i) the protracted timing required for Federal Energy Regulatory Commission approval of the installation and operation of the contemplated FSRU, (ii) the difficulty of obtaining land rights required for the construction of the Replacement CCGT Project, (iii) the challenges of attracting project financing for the Replacement CCGT Project due to the financial challenges PREPA faces and may continue to face once it emerges from the current Title III process, and (iv) the protracted time frames which have been required for PREPA (and more recently P3) to procure new generation in Puerto Rico generally. We also note that it is likely to be costly to procure alternative generation sources to bridge the timing gap in a scenario in which the currently effective EcoEléctrica PPOA lapses in 2022 but the Replacement CCGT Project actually achieves commercial operation only in 2025 or later.

PREPA believes that in the circumstances it should favor the course that is most likely to safeguard ratepayers against the risks of material delays in the timing of, and even the ability to implement, the Replacement CCGT Project. This conclusion is supported by an assessment of the alternatives recently performed by Siemens PTI/EBA using the Aurora model employed in the development of the IRP (the "EcoEléctrica New PPOA Assessment"), which is summarized in the memorandum accompanying this letter as Attachment 4. In performing the EcoEléctrica New PPOA Assessment, Siemens incorporated the Capacity Payment specified in the ECO PPOA, as well as the fuel pricing formula specified in the Naturgy GSPA. It also assumed that the ECO Facility would offer net dependable capacity of 530 MW, and a heat rates of 7.497 MMBtu/MWh at 507 MW and a heat rate at minimum load of 8.039 MMBtu/MWh (in line with the assumptions previously used in the IRP). Given these assumptions, the Aurora model found the ECO PPOA (as amended and restated from the PPOA assumed in earlier IRP model runs) to the be the most economic option under Scenario 4 relative to the alternative presented by the Replacement CCGT Project. Siemens found that signing the ECO PPOA would yield savings over the IRP study period having a Net Present Value of $705 million (or a cost reduction of 5%) relative to the alternative of not replacing the existing EcoEléctrica PPOA under Scenario 4 Strategy 2 with the ECO PPOA. Siemens concludes on the basis of the EcoEléctrica New PPOA Assessment that PREPA should seek to execute the new ECO PPOA and Naturgy GSPA.

On the basis of its analysis and the assessment Siemens has performed, PREPA has concluded that its execution of the ECO PPOA and the Naturgy GSPA are more likely to provide a secure and reliable source of power generation at the lowest reasonable costs than the

alternative of pursuing the Replacement CCGT Project. We intend to file in Docket No. CEPR-AP-2018-0001 an update in the analysis presented in the IRP Main Report to incorporate the assumptions included in the EcoEléctrica New PPOA Assessment and to reflect the conclusions summarized above. In the meantime, we invite you to let us know if you would like to discuss with PREPA and Siemens representatives the assumptions employed in and the results of these new model runs.

V. Request for Treatment of this Letter and Accompanying Documents as Confidential

PREPA requests that PREB treat this letter, the ECO PPOA (**Attachment 1**), the Naturgy GSPA (**Attachment 2**) and the Siemens analysis (**Attachment 4**) as Confidential because each contains information that qualifies as proprietary and includes trade secrets (*i.e.*, confidential and other protected information) which is protected under Puerto Rico law.[4] PREB regulations specifically provide for the designation of such information as Confidential.[5]

Act 80-2011 defines a trade secret as any information that:

> has a present or a potential independent financial value or that provides a business advantage, insofar as such information is not common knowledge or readily accessible through proper means by persons who could make a monetary profit from the use or disclosure of such information; and [f]or which reasonable security measures have been taken, as circumstances dictate, to maintain its confidentiality.

Trade secrets may take a variety of forms, including "a process to manufacture, treat or preserve materials, a formula or recipe, a project or pattern to develop machinery, or simply a list of specialized clients that constitute a specific market which provides the owner with an advantage over his/her competitors." These examples are not exhaustive, however, and the Legislative Assembly has acknowledged in Act 80-2011's Statement of Motives that the broad

[4] *See Industrial and Trade Secret Protection Act of Puerto Rico, as amended*, Act No. 80-2011; *see also Puerto Rico Energy Transformation and RELIEF Act, as amended*, Act No. 57-2014, § 6.15 (establishing that any person having the obligation to submit information to the Energy Bureau can request privileged or confidential treatment of any information which the submitting party believes to warrant such protection).

[5] Regulation 8815, § 10.2 (recognizing appropriateness of according proprietary information and trade secrets Confidential treatment); *cf.* Regulation 8594, § 1.15 (providing for designation of information submitted in support of an IRP as Confidential).

definition of a trade secret includes "any confidential information with trade or industrial value, which its owner reasonably protects to prevent its disclosure." In Puerto Rico, moreover, trade secrets "do not require registration or compliance with any formalities in order to be protected."

As the Legislative Assembly has noted, "failure to protect trade secrets could leave companies at the mercy of any competitor or former employee who gains knowledge of any such secret, whether directly from the owner or by other means."

As a public body whose costs are ultimately borne by citizens of Puerto Rico, PREPA has a strong interest in protecting both its own trade secrets and the trade secrets of actual and prospective vendors and contractors, such as EcoEléctrica and Naturgy, which entrust PREPA with such information in confidence as part of business and financial dealings. The information concerning pricing, dispatch, nomination procedures and the like incorporated into the proposed agreements with EcoEléctrica and Naturgy is proprietary, commercially sensitive and qualifies as trade secrets from the perspective of all parties involved. The disclosure of this information could place PREPA in a competitively disadvantageous position in dealing with other prospective electric power and natural gas suppliers, and therefore could impair PREPA's ability to acquire electric energy, capacity and fuel from the markets at the lowest cost, ultimately harming customers. Similarly, the disclosure of this information could adversely affect Naturgy in its negotiation of LNG and natural gas supply agreements with third parties.

Accordingly, PREPA respectfully requests that the PREB designate this letter, the ECO PPOA, the Naturgy GSPA and this letter as Confidential. Such a designation would be consistent with a number of Resolutions and Orders addressing PREPA's requests for confidential designations in the ongoing IRP proceeding, Docket No. CEPR-AP-2018-0001.[6] PREPA is prepared, should the PREB direct it to do so, to submit versions of this letter and the Attachments that are redacted to remove information qualifying as Confidential.

VI. Request for PREB Approval

PREPA hereby requests that, pursuant to Regulation 8815, Section 7.1, PREB review and approve the ECO PPOA and the Naturgy GSPA. PREPA includes with this letter as Attachment 3 the Resolution of the PREPA Governing Board approving the submission of these Agreements to the PREB and the FOMB for their review and approval and, subject to receipt of the required P3, FOMB and PREB approvals, the execution of the ECO PPOA and the Naturgy GSPA. PREPA further

[6] See, e.g., June 10, 2019 Resolution and Order, at p. 2; March 14, 2019 Resolution and Order, at p. 8; January 25, 2019 Resolution and Order, at p. 3.

requests that, for good cause shown, the PREB grant any waivers of the requirements of Regulation 8815 it may deem necessary to this end, and that it issue its approval within thirty (30) days of the date of this submission, as contemplated by Section 7.1(d) of said Regulation.

Please let us know if you have any questions concerning this letter or the attached Agreements.

Respectfully submitted,

José F. Ortiz Vázquez
Executive Director and Chief Executive Officer

Enclosed:

Attachment 1 – Amended and Restated Power Purchase and Operating Agreement between EcoEléctrica, L.P. and PREPA
Attachment 2 – Amended and Restated Natural Gas Sale and Purchase Agreement between Naturgy Aprovisionamientos S.A. and PREPA
Attachment 3 – PREPA Board Resolution dated October 31, 2019
Attachment 4 – Memo to PREPA CEO and IRP Team from Siemens PTI/AB dated October 2, 2019

Annex A

Capacity Payment Liability Risk

Reason for ECO Dispatch Curtailment / Non-availability	Party Taking Risk Under PPOA		Risk Mitigation Comments
	ECO	PREPA	
Grid Damage Caused by Hurricane	✓		PPOA grants PREPA relief from Capacity Payments for up to 30 days following occurrence of a hurricane – the same duration required to reestablish connection with the ECO Facility after Hurricane María.
Other FM Affecting PREPA		✓	PREPA may insure itself against certain risks.
Scale-Up of Solar Generation		✓	PREPA remits Capacity Payments each month regardless of volume of dispatch but has option to dispatch Ancillary Services in lieu of power to facilitate dispatch of Solar Generation from other sources during daytime hours.
Other New Sources of Generation		✓	PREPA controls introduction of future new sources of generation that will connect to the Grid.
Grid Constraints		✓	PREPA owns / operates Grid System and will oversee the construction of the Permanent Grid System.
Reduced Electricity Demand		✓	
FM Affecting ECO Facility	✓		See item (ii) of Appendix C of the PPOA (FMAF)
Forced Outage	✓		See item (ii) of Appendix C of the PPOA (EAF)
Derating	✓		See item (ii) of Appendix C of the PPOA (EAF)
Scheduled Maintenance	✓		See item (ii) of Appendix C of the PPOA (EAF)
Unscheduled Maintenance	✓		See item (ii) of Appendix C of the PPOA (EAF)
Gas Supply Interruption (FM Affecting Naturgy)		✓	ECO operates Facility utilizing back-up fuel (diesel) during period of gas supply interruption and PREPA reimburses ECO for cost of back-up fuel.
Gas Supply Interruption (Temp. ECO TA Default)		✓	While PREPA pays Capacity Payments and cost of back-up fuel to ECO, Naturgy reimburses PREPA for excess cost of back-up fuel and "unutilized" capacity under Section 9 of the GSPA (the "Naturgy Reimbursement").

Reason for ECO Dispatch Curtailment / Non-availability	Party Taking Risk Under PPOA		Risk Mitigation Comments
	ECO	PREPA	
Gas Supply Interruption (ECO TA Default / Termination)	✓ (>30 days)	✓ (first 30 days)	While PREPA pays Capacity Payments and cost of back-up fuel to ECO for 30 days following termination of TA, the Naturgy Reimbursement applies. PREPA has right to terminate PPOA 30 days after termination of TA under Section 18.1 of the PPOA.
Gas Supply Interruption (All Other Reasons)		✓	While PREPA pays Capacity Payments and cost of back-up fuel to ECO, the Naturgy Reimbursement applies.

Annex B

Natural Gas Supply Interruption Risk

Reason For Shortfall/Non-availability of, or PREPA Inability to Accept, Natural Gas	Party Taking Risk Under GSPA		Risk Mitigation Comments
	Naturgy	PREPA	
Grid Damage Caused by Hurricane	✓		Under Clause 15.1(f), an interruption to the Grid System, whether caused by a hurricane or otherwise qualifies as a force majeure event relieving PREPA from its obligations to purchase natural gas. Pursuant to Clauses 15.9 and 18.1(b)(ix), if the FM event is not resolved within 180 days, Naturgy may terminate the agreement, however PREPA may begin to accept deliveries of natural gas, but reduce its minimum annual contract quantity which will keep the agreement in force.
Other FM Affecting PREPA	✓		Pursuant to Clause 15, FM events directly affecting PREPA generally will allow PREPA to suspend its obligations to purchase natural gas.
Scale-Up of Solar / Renewable Generation	✓ (≥19TBtu)	✓ (<19TBtu)	Clause 6.2(e) of the GSPA allows PREPA to reduce the minimum annual quantity of natural gas purchased if the proportion of renewable generation sources exceeds 15% of the total power generated by sources connected to the Grid System to as low as 19 TBtu. PREPA bears risk if taking below this level.
Reduced Electricity Demand	✓ (≥19TBtu)	✓ (<19TBtu)	If peak electricity demand in Puerto Rico falls below two thousand three hundred (2,300) megawatts PREPA may reduce the minimum annual contract quantity to as low as 19 TBtu pursuant to Clause 6.2(d). PREPA bears risk if taking below this level.
FM Affecting ECO Facility	✓		Both Naturgy and PREPA are relieved from their obligations to deliver and

Reason For Shortfall/Non-availability of, or PREPA Inability to Accept, Natural Gas	Party Taking Risk Under GSPA		Risk Mitigation Comments
	Naturgy	PREPA	
			purchase natural gas, respectively, to the extent of the ECO Facility FM pursuant to Clause 15, but deliveries may be made at Costa Sur.
Forced Outage	✓		A forced outage either at ECO or Costa Sur Units relieves PREPA from take-or-pay liability under Clauses 8.2(b) and 8.4(e) of the GSPA.
Derating at ECO / Costa Sur Facilities		✓	
Scheduled Maintenance	✓		Scheduled maintenance shall reduce the minimum annual contract quantity for the relevant year proportionally to the duration of the scheduled maintenance pursuant to Clause 6.2(b)
Unscheduled Maintenance		✓	Unscheduled maintenance events that occur for reasons other than Force Majeure result in take-or-pay liability to PREPA.
Gas Supply Interruption (FM Affecting Naturgy)		✓	Clause 15 of the GSPA contemplates relief afforded to Naturgy for its failure to deliver natural gas under an FM event, such as issues affecting the LNG ships or LNG loading facilities. In those instances, PREPA will have to use and pay for back-up fuel to generate electricity.
Gas Supply Interruption (Naturgy breach of the GSPA)	✓		For a general failure of Naturgy to deliver natural gas, Clause 9 of the GSPA provides protections for PREPA in the form of damages. For failures to deliver at the Costa Sur Units, Naturgy pays liquidated damages equal to 15% of the contract price for the relevant shortfall quantity during the quarter in which such shortfall occurred. For a failure to deliver at the ECO Facility, Naturgy reimburses PREPA for capacity payments made to ECO for any unused

Reason For Shortfall/Non-availability of, or PREPA Inability to Accept, Natural Gas	Party Taking Risk Under GSPA		Risk Mitigation Comments
	Naturgy	PREPA	
			capacity resulting from the shortfall as well as all of its actual and documented costs associated with utilizing back-up fuel.

Attachment 1

Amended and Restated Power Purchase and Operating Agreement between EcoEléctrica, L.P. and the Puerto Rico Electric Power Authority

CONFIDENTIAL

Attachment 2

Amended and Restated Natural Gas Sale and Purchase Agreement between Naturgy Aprovisionamientos S.A. and the Puerto Rico Electric Power Authority

CONFIDENTIAL

Attachment 3

PREPA Board Resolution 4745 dated October 29, 2019

Attachment 4

Memo to PREPA CEO and IRP Team from Siemens PTI/AB dated October 2, 2019

CONFIDENTIAL

UTIER MTA Exhibit 6

Puerto Rico
Electric Power
Authority

Puerto Rico Electric Power Authority

EcoEléctrica and Naturgy Proposed Contract Extensions

August 7, 2019

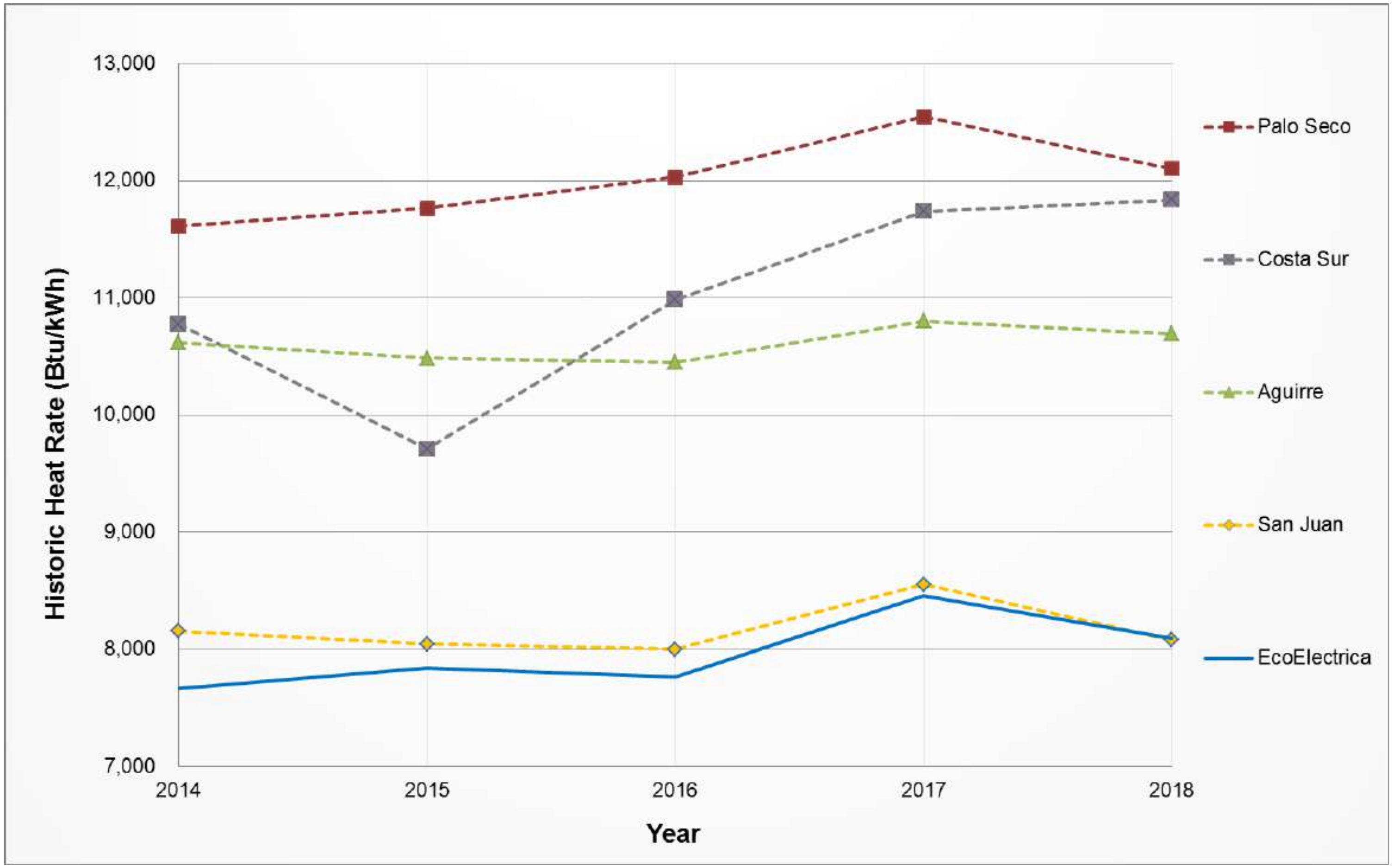
ECOELÉCTRICA POWER PLANT

- **Plant Overview**
  - Combined Cycle Gas Turbine Plant in Peñuelas, Ponce region
  - Capacity: 507 MW
  - Commercial Operation Date: March 2000
  - Natural gas is supplied through the Peñuelas LNG Terminal
    - PREPA does not legally have access to the LNG Terminal

- **Operational Metrics**
  - Original heat rate: 7,497 Btu/kWh
  - Average 2013-2016 values:
    - Heat rate: 7,747 Btu/kWh
    - Availability: 90%
    - Capacity Factor: 76%

ECOELÉCTRICA POWER PLANT

- The following chart compares the historic heat rate of EcoEléctrica to PREPA's other base-load power plants

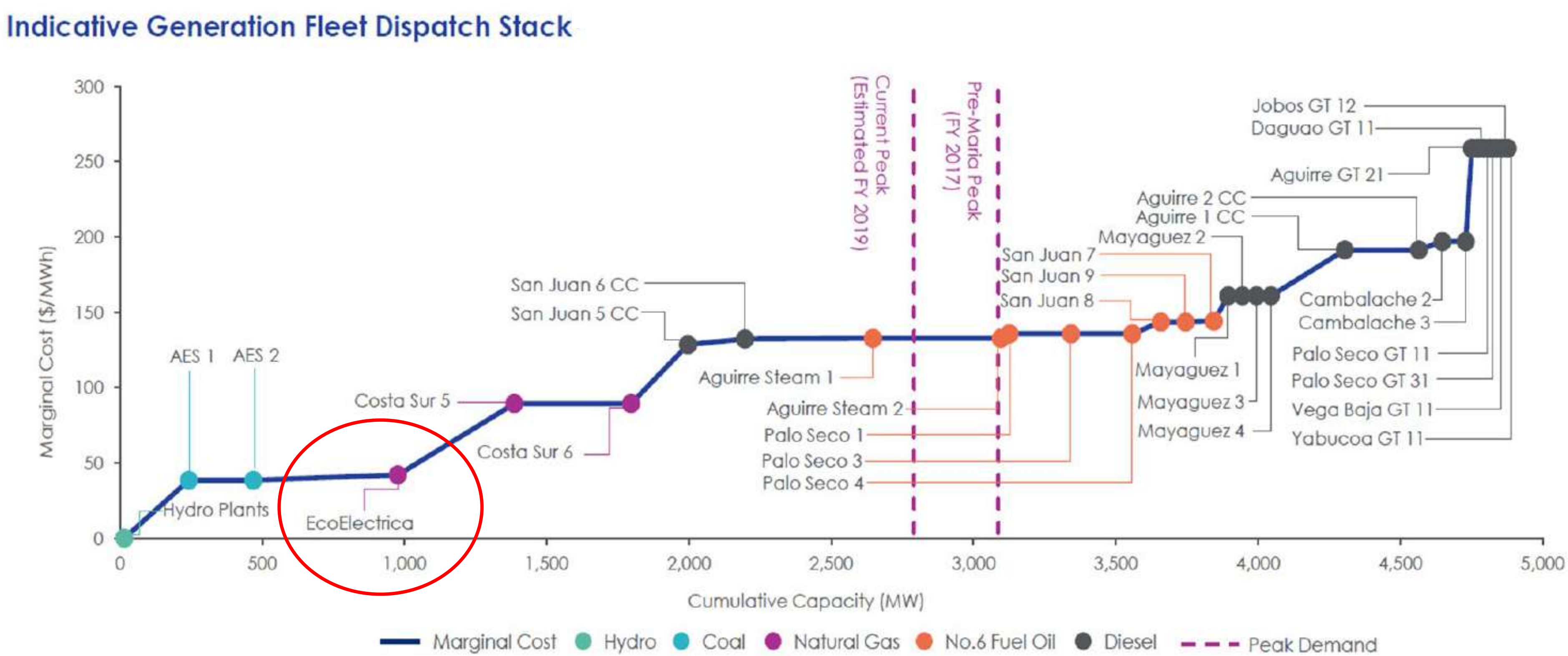


PREPA-00419

Puerto Rico Electric Power Authority

ECOELÉCTRICA POWER PLANT

- The chart below provides economic dispatch merit order positions for PREPA units
  - Compares marginal facility operation cost to total unit/system capacity
  - EcoEléctrica is one of the cheapest units to operate in Puerto Rico



Puerto Rico Electric Power Authority

CONTRACT NEGOTIATION STRATEGY

Negotiations on the term sheets have progressed over 12 months

PREPA pursued negotiations focusing on the following items:

1) Meet or exceed Fiscal Plan savings targets

- Fiscal plan targets $80 million in savings per year

2) Increase, not decrease, flexibility for PREPA

- PREPA is transitioning to renewable energy, making grid improvements, and building new facilities
- New contracts should help make this transition easier, not more difficult

PREPA used the IRP as a high level guide and for negotiation leverage

CONTRACTS COMPARISON

	Existing Contract	Proposed Term Sheets
PPOA with EcoEléctrica		
Contract Term	Mar-22	Sep-32
Contract Structure	Capacity Payment + Energy Payment	Capacity Payment only
Key Element Capacity Payment Amount	Approximately **$225 million per year**	**Reduced by $108 M per year** (to approximately $117 M) (Reduction subject to an availability adjustment)
Energy Payment	Payment for net electrical output of the facility intended to cover fuel expenses. Average of **5.5 cents/kWh** per year	Replaced by direct fuel payments (GSA). Average of **7.1 cents/kWh** per year
Availability Adjustment	Penalty and bonus for low and high availability	Equivalent structure, with a higher bonus potential
Key Element Max / Min Dispatch Level	Set at 54% and 76% of available capacity. At >76% capacity factor, fuel expenses were at spot market price[1](80% higher)	Dispatch constraints removed. EcoEléctrica can now be dispatched above 76% capacity factor with no fuel premium
Maximum Start-ups	Limit of 50 starts per year	Will be increased to allow for future cycling operation

GSA with Naturgy		
Contract Term	Dec-20	Sep-32
Facilities Covered	Costa Sur	Costa Sur and EcoEléctrica
Pricing Formula	Pricing currently includes a hedge to No. 6 fuel oil	Price based solely on price of natural gas, hedge removed
Minimum Annual Contract Quantity	45 TBtu (Costa Sur only)	55 TBtu (Costa Sur and ECO), PREPA will have flexibility to reduce the minimum contract quantity for macro-level events

1) The "Spot Price" as defined in the existing contract is not the same as the market price

PREPA-00422

Puerto Rico Electric Power Authority

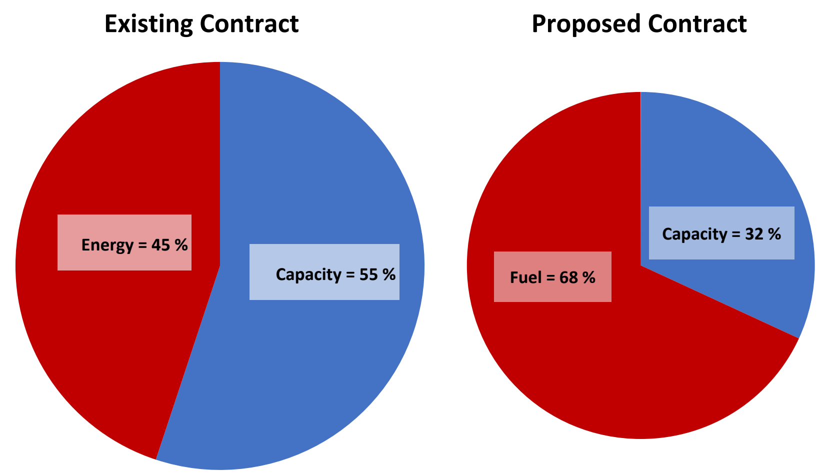
CONTRACT COMPARISON – KEY ELEMENTS

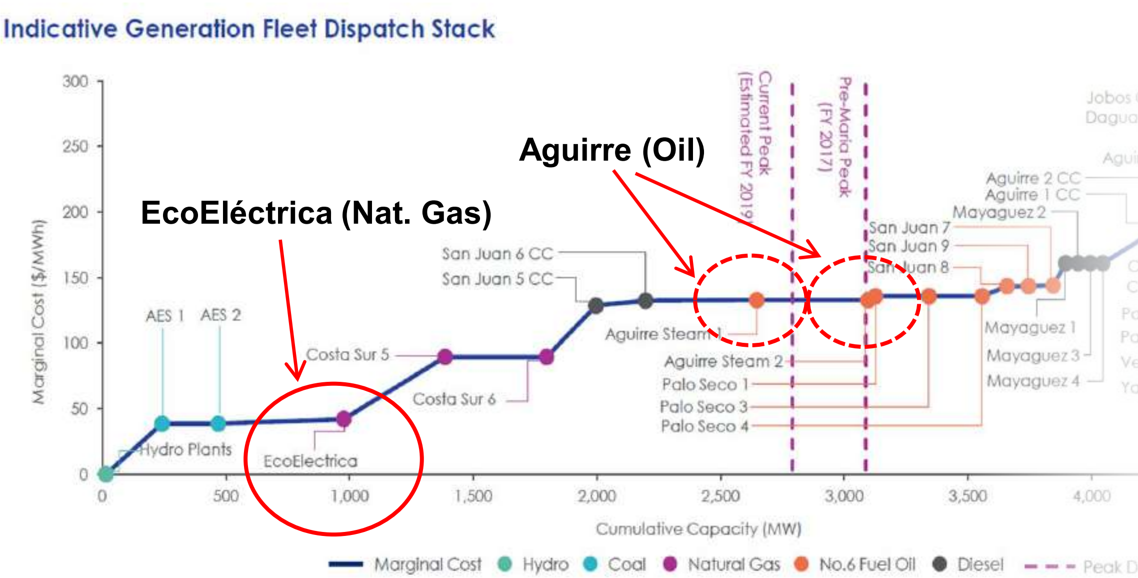
- Capacity payment reduced by $108 M

  (from $225 M to $117 M annually)
- Fuel expenses increased

Net result is $63.5 M per year in savings for PREPA

Breakdown Between Capacity and Fuel Payments





- 76% capacity factor constraint is removed
- ECO's generation will increase
- Less generation needed from inefficient and expensive generators, i.e. Aguirre

Aguirre Fuel savings estimated to be $50 M per year

PREPA-00423

Puerto Rico Electric Power Authority

CONTRACT DISCUSSION

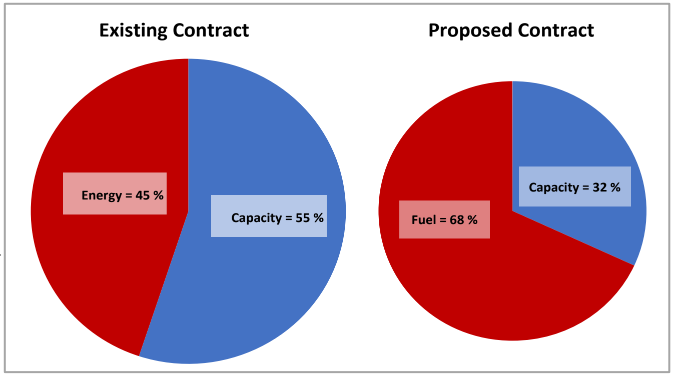
The proposed contracts will also result in the following:

1) Additional savings of approximately **$31.5 M per year** in fuel for Costa Sur, due to the removal of a price hedge to oil in the natural gas pricing formula. Total savings equal $113.5 M (previous slide) + $31.5 M = **$145 M annually**

- Exceeds Fiscal Plan target of $80 M

2) Increased flexibility for PREPA - contracts are better suited for renewable generation growth

- PPOA increases the number of allowed starts per year for future cycling operation
- GSA includes take or pay relief through exercisable macro-level options i.e., Costa Sur closure, falling demand, > generation from 15% renewables
- If ECO cycles more due to more renewables, new contracts will result in lower payments than under existing contract
  - Higher percentage of payments are allocated to fuel rather capacity



3) Increased grid reliability

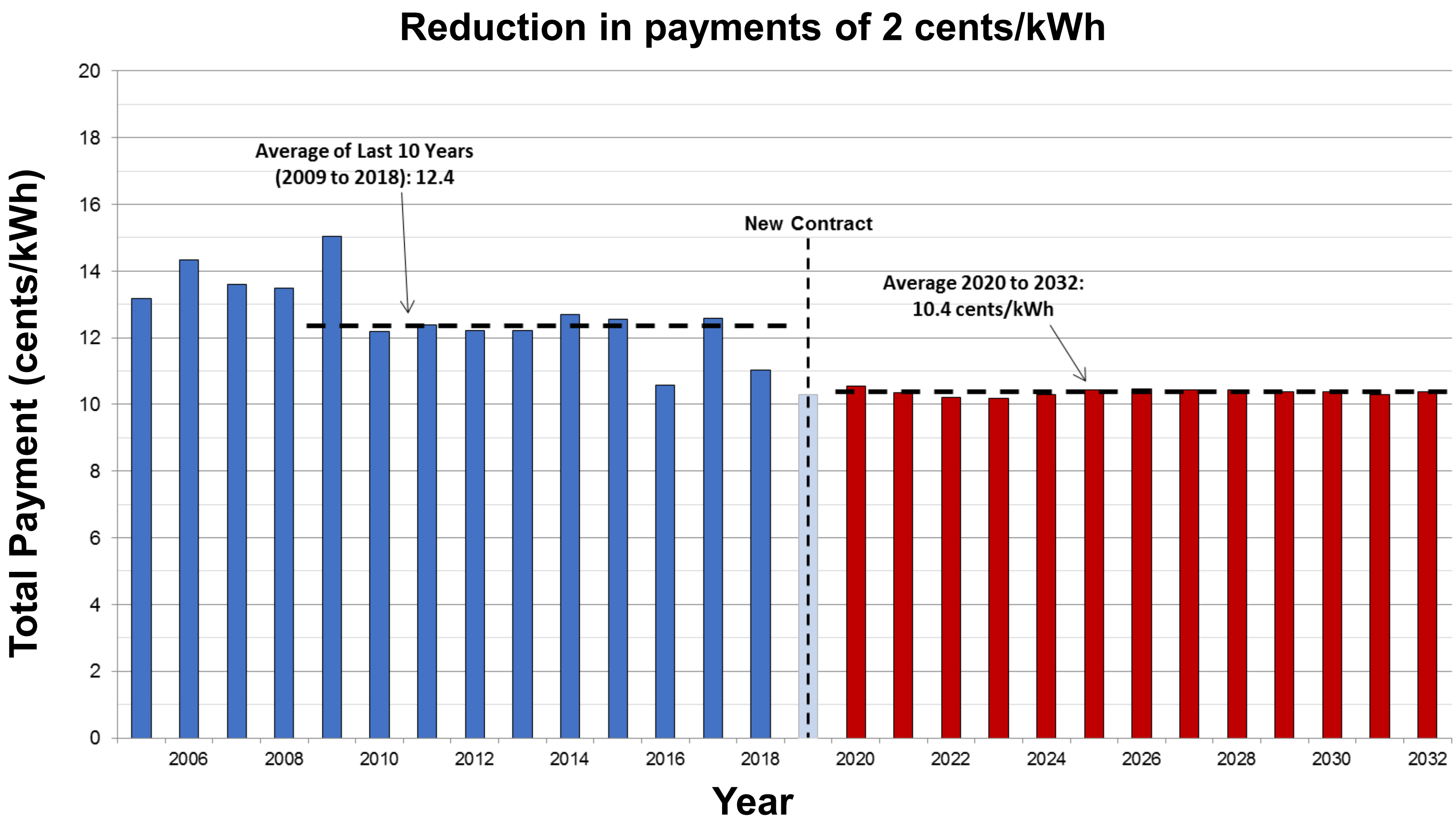
- Increased dispatch of EcoEléctrica, one of the most reliable generators in Puerto Rico, will result in less generation needed from unreliable generators

PREPA-00424

Puerto Rico Electric Power Authority

FINANCIAL CALCULATIONS – RESULTS

EcoEléctrica Historical Payments Compared to Forecasted (cents/kWh)



Historic capacity factor approximately 76%, forecasted at 84% (per PREPA dispatch center)

PREPA-00425

Puerto Rico Electric Power Authority

ALTERNATIVE CASE – CLOSE ECOELÉCTRICA

PREPA does not have rights to operate the Peñuelas LNG terminal

- PREPA would have to pay a higher price for gas delivered to a new CC at Costa Sur because Naturgy owns the LNG terminal
- Shipments of LNG from elsewhere would need to be gasified at the Peñuelas LNG terminal
- Technically, PREPA does not have any other options than the Peñuelas LNG terminal
  - The price to build an LNG terminal is over $600M and would require years for construction, FERC approval, and permitting
  - Pipelines of natural gas from elsewhere are expensive and there is strong public opposition
  - Truck delivery of gas is not feasible because of volume of gas required
- Without EcoEléctrica, substantial modifications would need to be made to the LNG terminal to power the facility and allow for gas delivery supply bypassing EcoEléctrica

Puerto Rico Electric Power Authority

ALTERNATIVE CASE – CLOSE ECOELÉCTRICA

If PREPA does not renegotiate with EcoEléctrica, the facility shuts down. PREPA has to replace 15% of the island's generation at the end of 2022 (when the PPOA expires)

- A new combined cycle facility at Costa Sur (per IRP) would not be completed until 2025 (at the earliest)
- PREPA would need to replace 500 MW of baseload generation between 2022 and, at earliest, 2025
  - This replacement generation would likely be from less efficient generators that burn expensive fuel. We estimate fuel costs will be **$100 M more annually**

Naturgy would likely raise natural gas costs for Costa Sur because PREPA has no other feasible options for natural gas supply

- Price could rise to facility's replacement fuel price (bunker oil)
- This would cost PREPA an **additional $140 M annually** in fuel costs
- Would apply to both Costa Sur (existing) and likely the future Eco replacement facility

ALTERNATIVE CASE – REJECT CURRENT CONTRACTS

PREPA has the legal right to reject the existing contracts

- Right falls under Bankruptcy Code Section 365(a) and PROMESA

<u>GSA Rejection</u>

- Naturgy owns LNG regasification facility
- Rejection of GSA would end gas supply to Costa Sur and there are no other feasible gas supply options
- PREPA would likely be forced to pay substantially more for gas

<u>PPOA Rejection</u>

- PREPA could buy energy from EcoEléctrica at PREPA's total avoided cost
  - The total avoided cost is likely higher than the current price of energy from Eco
- EcoEléctrica could mothball the facility until PREPA meets its demands
  - EcoEléctrica and Costa Sur provide > 50% of PREPA's electricity – this would lead to significant financial and publicity challenges

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FINAL

EcoEléctrica and Naturgy Contract Renegotiations

Prepared for

The Puerto Rico Electric Power Authority

Document No. CS-0022
S&L Project No. 13741-017/018
November 19 2019

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VERSION LOG

Version	Issue Date
Draft	5 August 2019
Revision	16 August 2019
Revision	22 October 2019
Final	19 November 2019

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TABLES AND FIGURES

ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
BLS	U. S. Bureau of Labor Statistics
CPI	Consumer Price Index
EAF	Equivalent Availability Factor
FERC	Federal Energy Regulatory Commission
GSA	Gas Sales Agreement
IRP	Integrated Resource Plan
LNG	Liquefied Natural Gas
Max ACQ	Maximum Annual Contracted Quantity of Natural Gas
Min ACQ	Minimum Annual Contracted Quantity of Natural Gas
MMBtu	Metric million British thermal unit
MMcf	Metric Million cubic feet
O&M	Operations and Maintenance
PPOA	Power Purchase and Operating Agreement
PREB	Puerto Rico Energy Bureau
PREPA	Puerto Rico Electric Power Authority
PROMESA	Puerto Rico Oversight, Management, and Economic Stability Act
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility

EXECUTIVE SUMMARY

The EcoEléctrica Power Plant is a 507-megawatt cogeneration facility owned by Naturgy, ENGIE SA, and Mitsui & Co., located in Peñuelas, Puerto Rico. Commercial operation began in March 2000. EcoEléctrica supplies approximately 15% of Puerto Rico's electricity. The EcoEléctrica plant is one of the most reliable, lowest cost, and efficient generators in Puerto Rico. PREPA entered into a Power Purchase and Operating Agreement (PPOA) with EcoEléctrica in 1995. Gas for EcoEléctrica is provided through the Peñuelas LNG import terminal, which has been operating since 2000. Currently, this is the only LNG terminal on the island with the capability to import, store, regasify, and export natural gas. The Peñuelas LNG import terminal is owned by Naturgy.

PREPA's Costa Sur Power Plant is an 820-megawatt facility located adjacent to EcoEléctrica that began commercial operation in the late 1960s. Costa Sur is currently the only PREPA-owned facility capable of firing natural gas. PREPA entered into a Gas Sales Agreement (GSA) with Naturgy for the supply of natural gas to Costa Sur Units 5 and 6 in 2012. Naturgy supplies natural gas to Costa Sur via a short pipeline from EcoEléctrica. As of May 2018, Costa Sur has been burning exclusively natural gas.

Over the last year, PREPA has been in discussion with both EcoEléctrica and Naturgy, the fuel supplier and majority shareholder of the EcoEléctrica facility, to negotiate amendments and extensions to the existing PPOA and existing GSA in such a way that lowers electricity costs to Puerto Rican ratepayers, improves the reliability of the electrical system, and aligns with PREPA's long-term renewable goals. In our opinion, the proposed amended PPOA and GSA with EcoEléctrica and Naturgy, respectively, achieve PREPA's objectives. For this reason, we recommend PREPA finalize and accept the amended contracts.

PROPOSED AMENDMENTS

Contract negotiations were pursued aiming to separate capacity and energy payments in the existing PPOA into two contracts. In the amended contracts, capacity payments are established under an amended and restated PPOA with EcoEléctrica, while the current energy payment in the existing PPOA changes to a direct fuel payment through the amended GSA with Naturgy. This amended GSA now covers the supply of natural gas to both EcoEléctrica and PREPA's adjacent Costa Sur facility.

The key differences between the existing and proposed amended PPOA and GSA are shown in the table as follows.

Table ES-1 — Comparison of Existing and Proposed Contract Terms

	Existing Contract	Proposed Amendments
PPOA with EcoEléctrica		
Contract Term	March 2022	September 2032
Nature of Contract	Capacity Payment + Energy Payment	Capacity Payment only
Available Capacity	507 MW	530 MW
Capacity Payment Amount	Approximately $230 M per year at 507 MW (corresponding to $241 M per year at 530 MW)	Approximately $128 M per year at 530 MW (subject to an availability adjustment)
Energy Payment	Compensation for net electrical output of the facility intended to cover fuel expenses. Average of 5.6 cents/kWh per year. Above a 76% capacity factor fuel costs increase to approximately 80% higher	Replaced by direct fuel payments. Estimated to be 7.1 cents per kWh per year
Availability Adjustment	Penalty and bonus for low and high availability	Equivalent structure, with a higher bonus potential
Max / Min Dispatch Level	Set at 54% and 76% of available capacity. Above a 76% capacity factor and fuel costs increase to 'spot price', approximately 80% higher.	Levels have been removed. EcoEléctrica can now be dispatched above 76% capacity factor with no fuel premium
Maximum Start-ups	Limit of 50 starts per year	This number will be increased to allow for future cycling operation
GSA with Naturgy		
Contract Term	December 2020	September 2032
Facilities Covered	Costa Sur	Costa Sur and EcoEléctrica
Pricing Formula	Pricing currently includes a hedge to No. 6 fuel oil	Price based solely on price of natural gas and natural gas price adder reduced by 8%
Minimum Annual Contract Quantity	45 TBtu (Costa Sur only)	55 TBtu (Costa Sur and EcoEléctrica combined), PREPA has flexibility to reduce the minimum contract quantity for various macro-level events

IMPACT OF PROPOSED AMENDMENTS

The key items in the proposed amendments and their impacts are listed below:

Financial Savings: We estimate that the terms of the proposed amendments would amount to savings for PREPA of approximately $100 million per year, of which $71 million are derived from EcoEléctrica and $29 million are derived from Costa Sur. Savings tied to Costa Sur are expected to be modest over the first five years, averaging approximately $10 million per year. Given this, total savings are expected to be approximately $81 million per year over the next five years. Note that these savings figures meet the Fiscal Plan's savings target of $80 million assigned to the renegotiation of existing PPOAs. We break total savings into three sources, as is discussed as follows:

1) The combined charges for EcoEléctrica are reduced. PREPA negotiated a reduction in the capacity payment equal to $108 million annually (offset by an availability bonus). However, these savings are partially offset by increased fuel costs. We estimate the net reduction corresponds to approximately $35 million annually in savings for PREPA. This value is calculated by comparing expected payments under each contract structure at the historical average generation level of 3.33 million MWh (a 75% capacity factor). Note that since the available capacity increases from 507 MW to 530 MW in the new contract, this generation level corresponds to two different capacity factors for each contract, 75% for 507 MW (existing contract) and 71.7% for 530 MW (proposed contract). The total calculated cost for each contract structure is shown below:

Table ES-2 — Comparison of Existing and Proposed Contract Costs

	Existing Contract Structure	Proposed Contract Structure
Generation (MWh)	3,330,452	
Available Capacity (MW)	507 MW	530 MW
Capacity Factor	75.0%	71.7%
Capacity Payment (millions of USD)	$225.0 M	$148.1 M[1]
Total Fuel Payment (millions of USD)	$186.7 M	$228.6 M
Total Payment (Million USD)	$411.7 M	$376.7 M
Difference (Million USD)	**$35.0 M**	

1) Capacity payment includes discount, offset by the estimated availability bonus

2) Existing financial limitations on the dispatch of the EcoEléctrica facility are removed. Under the existing contract, if PREPA dispatches EcoEléctrica at capacity factors higher than 76%, PREPA must to pay a higher fuel cost for generation above the 76% threshold. The specific cost of this additional fuel varies based on both market conditions and Naturgy's internal costs, but the most recent Puerto Rico Integrated Resource Plan (IRP) lists this cost ($ per MMBtu) at approximately 80% higher than the contracted fuel cost. For this reason, at times when EcoEléctrica's capacity factor would go above 76%, PREPA sometimes chooses to dispatch other facilities instead of EcoEléctrica on the basis of economics. The proposed contract removes this fuel pricing feature so that now natural gas utilized for generation at EcoEléctrica will be the same cost per MMBtu regardless of the facility's capacity factor. The PREPA Dispatch Center has indicated that they expect this change will allow PREPA to dispatch EcoEléctrica at an 84% capacity factor going forward. They also indicated that this generation is likely to come from the Aguirre steam facility, the marginal generator on the island, even with existing transmission constraints.

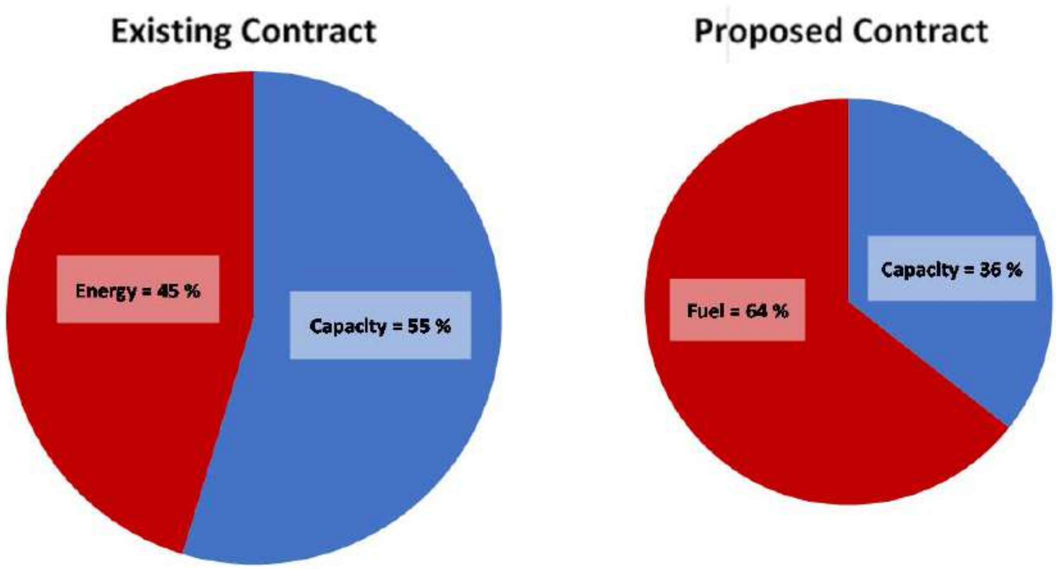
   Increasing the generation of EcoEléctrica from 3.33 million MWh (corresponding to the average historic capacity factor of 75%) to 3.90 million MWh (corresponding to the facility operating at an 84% capacity factor) will cost PREPA and additional $39 million in natural gas costs. However, the additional 0.57 million MWh generated at EcoEléctrica will not be generated at Aguirre, which will save PREPA a total of $74 million in Aguirre's fuel expenses and just over $1 million in Aguirre's variable operations and maintenance (O&M) costs, for a net total savings of $36 million annually.

3) The existing GSA for Costa Sur has a built-in pricing hedge to oil, which was removed in the proposed contract. Given that natural gas prices are forecasted to remain much lower than oil prices over the next decade, we estimate that removing the hedge to oil and reducing the adder fee will result in average savings for PREPA of approximately $29 million per year for the Costa Sur facility. These savings are based upon fuel commodity price forecasts. Note that savings are expected to be modest over the first five years, averaging approximately $10 million per year, and increase in the future due to the forecasted widening of the spread between natural gas and oil prices.

Increased Flexibility: The proposed contracts give PREPA more flexibility than the current agreements, particularly related to addressing potential challenges that arise from increased renewable energy generation. This flexibility is described below:

1) Under the existing contracts, a greater percentage of the total payment to EcoEléctrica goes to cover the fixed capacity charge. The proposed contracts' financial structure would result in a greater percentage of the total payments to EcoEléctrica's operation going towards variable fuel costs. The following graphic compares the cost breakdown of the existing contract with the proposed contracts.

Figure ES-1 — Existing Versus Proposed Contract Payment Breakdown



As a result of a greater percentage of overall payments being tied to the variable fuel costs, the total cost to PREPA for EcoEléctrica's operation would fall significantly if EcoEléctrica was dispatched less. This situation will become more common as additional renewable energy plants are installed across Puerto Rico. For this reason, we expect the total MWh generation for EcoEléctrica to fall in the future. Under the proposed contract structure, reduced generation results in a reduction of the total payments to EcoEléctrica; thus, we are of the opinion that the proposed contracts' payment structure better aligns with PREPA's long-term renewable energy goals.

2) The proposed contract also increases the number of allowed starts of EcoEléctrica per year. Under the current contract, there is a limit of 50 starts per year. The proposed contract specifies that this will be increased. Increasing the number of allowed starts of the EcoEléctrica facility gives PREPA the flexibility that it needs to use EcoEléctrica as a cycling facility in the future as more renewable generation is installed.

3) The GSA includes options to reduce PREPA's take or pay obligations. PREPA has the option to reduce take or pay obligations if: a) Costa Sur is shut down; b) demand on the island falls; or c) if renewable energy generation increases to a point where less natural gas is needed for EcoEléctrica or Costa Sur. These options are not tied together in that PREPA could potentially exercise all three at different times if the associated criteria were met. These take or pay reduction options allow PREPA additional flexibility going forward to better match the amount of natural gas purchased to the needs of the electrical grid at that time.

Increased Reliability: As described above, the existing PPOA with EcoEléctrica charges PREPA more for natural gas (in the form of an energy payment), in the event the facility is dispatched above a 76% capacity factor. The proposed contract with EcoEléctrica removes this feature. PREPA's Dispatch Center has indicated that removing this financial constraint from the existing contract will allow EcoEléctrica to be dispatched at a higher capacity factor, estimated at approximately 84% capacity factor. Given that EcoEléctrica has historically been the most reliable generator in Puerto Rico, dispatching EcoEléctrica at a higher level will result in less generation being needed from other, less reliable generators on the island. In our opinion, this should increase the electrical reliability of PREPA's power grid.

If the proposed contracts with EcoEléctrica and Naturgy are not pursued, we consider two alternative strategies that PREPA can take.

Strategy A: PREPA can allow the PPOA with EcoEléctrica to expire in 2022 and build a new combined cycle power plant, potentially at Costa Sur. This scenario is considered in the IRP. There are two main challenges associated with this scenario: 1) PREPA does not have access rights to the Peñuelas LNG terminal (Naturgy has exclusive rights of this facility) and 2) PREPA would not be able to build a replacement facility before the end of the existing PPOA with EcoEléctrica. This scenario has the potential to cost PREPA an estimated **$240 million annually** in extra fuel costs until a new combined cycle is built.

1) Regarding the first issue, PREPA does not have any technically viable alternatives to import natural gas in the south of the island other than the Peñuelas LNG terminal. Construction of another terminal is cost prohibitive, at an estimated $600 million (per the IRP) and would potentially take years for FERC approval, design, and construction. Additionally, maritime constraints tied to the Jones Act further limit PREPA's ability to cost effectively move gas from one place to another. Alternatively, piping natural gas from other locations is expensive and lacks public support, while trucking LNG from other locations is also expensive and not efficient given the volume of LNG that would be needed. Therefore, we are of the opinion that Naturgy would have substantial leverage in a future negotiation and would charge more for natural gas than currently proposed. We estimate that starting in 2021 (after expiration of the current GSA) and up until when a new combined cycle is built, Naturgy could charge PREPA up to 25% more for natural gas to the existing Costa Sur facility. The 25% increase would make the cost of natural gas equal to the cost of bunker fuel oil, the alternative fuel for Costa Sur. This could cost PREPA an additional **$140 million** in fuel costs for Costa Sur annually. Note that this scenario is not without precedence as a similar situation transpired earlier this year with diesel fuel.

   There is also the potential that the Peñuelas LNG terminal shuts down following the closure of EcoEléctrica, because the terminal requires EcoEléctrica to operate. Operation of the terminal without EcoEléctrica is not possible without modifications to the terminal. In either case, if the terminal is unavailable, there is unlikely that PREPA would be able to obtain natural gas for Costa Sur. In this scenario, Costa Sur would be forced to burn bunker fuel, which would not only cost PREPA an additional $140 million annually, but also could put Costa Sur in violation of emissions regulations.

2) The second issue highlights that PREPA would have to replace over 500 MW of baseload generation between the expiration of the EcoEléctrica PPOA in 2022 and when a replacement facility could be built, which is estimated to be 2025 by the IRP at the earliest. Given PREPA's aging generation fleet and electrical grid limitations, it will be challenging for PREPA to bridge this gap. It is likely that PREPA would have to increase dispatch of its existing, less efficient generators that burn more expensive diesel and/or bunker fuel. A likely scenario would be that Aguirre would replace EcoEléctrica's generation, in which case PREPA could incur over **$100 million** in increased fuel costs annually.

Strategy B: Under this strategy, PREPA would not pursue finalizing the renegotiated contracts. Instead, PREPA would reject one or both existing contracts (EcoEléctrica PPOA and/or Naturgy GSA). The goal of this legal action would be to force better financial terms for PREPA. We view this as a risky strategy since it has the potential to lead to substantially worse outcomes for PREPA. A brief discussion of the strategy and an associated analysis is provided below:

1) PREPA has the right to reject the existing GSA and PPOA. Bankruptcy Code section 365(a), as incorporated into the Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA), provides that PREPA, subject to the court's approval, may assume or reject any executory contract, which includes the GSA and PPOA. However, rejection by PREPA would constitute a breach of the contract and that gives the counterparty a claim for any damages or loss suffered as a result of the rejection.

2) Given that Naturgy has exclusive control over the capacity of the Peñuelas regasification facility, if PREPA rejects the GSA in order to extract more concessions from Naturgy, Costa Sur will as a practical matter lose access to natural gas. Given Naturgy's ownership of the only natural gas facilities serving Costa Sur, no other natural gas supplier will have the ability to deliver gas to the Costa Sur plant without Naturgy's consent. PREPA will have to pay a premium to secure such consent (and/or terminal use rights); burn back-up fuel at Costa Sur (which may be practically and legally difficult given emissions limitations that may apply); and/or re-enter gas supply arrangements with Naturgy, likely at a much higher price.

3) Rejection of the PPOA could play out in several different ways. One result would be that EcoEléctrica would sell its energy to PREPA at PREPA's avoided cost (the "PURPA Put"). PREPA has internally conducted studies of its avoided costs, and there is evidence that they are substantially higher than the costs currently paid to EcoEléctrica. Another option is that EcoEléctrica could decide not to exercise its right to the PURPA Put and instead to mothball the facility until PREPA agreed to its pricing demands. According to EcoEléctrica, if it does not move LNG/natural gas through the regasification terminal, then the terminal lacks sufficient throughput on Costa Sur alone to maintain continuous operations. EcoEléctrica and Costa Sur provide just over 40% of the electricity for the island. Losing both plants would likely result in political and public backlash against PREPA, in addition to the obviously significant financial impact.

Sargent & Lundy considers the proposed contracts with EcoEléctrica and Naturgy to be in the best interest of PREPA for the aforementioned reasons. Not only would the contracts place PREPA in a better position financially and operationally, but the proposed contracts represent the best option currently available to PREPA. Given the constraints and limitations that are in place for PREPA, we recommend that PREPA finalize and accept the renegotiated PPOA and GSA to realize the savings and impact to ratepayers described herein.

REPORT PREPARERS

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Reviewed and Approved by:	Dennis Zabala Principal Advisor	November 19, 2019 Date

1. INTRODUCTION

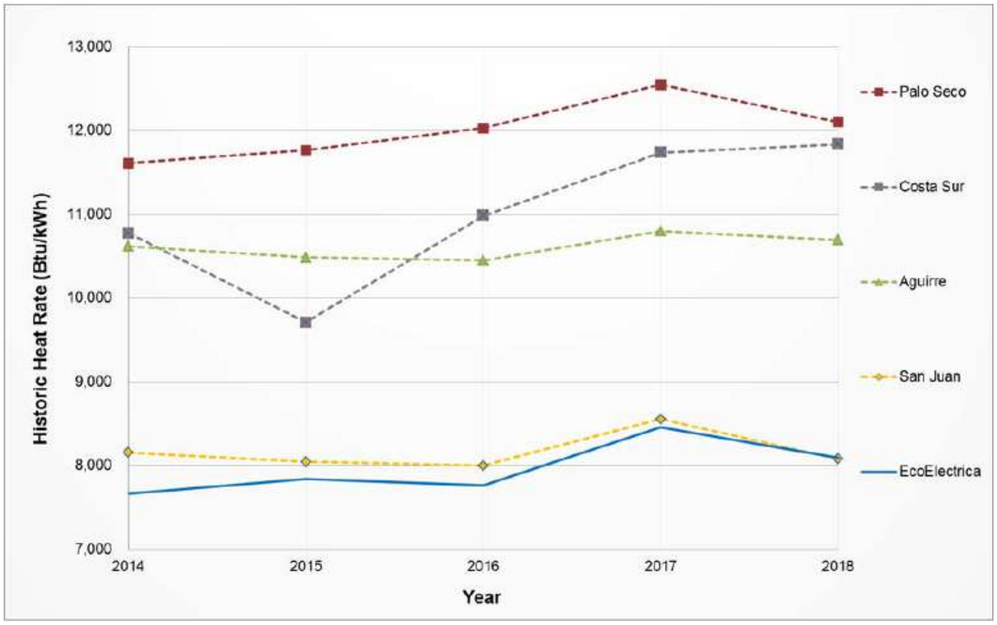
The EcoEléctrica Power Plant is a 507-megawatt cogeneration facility owned by Naturgy, ENGIE SA, and Mitsui & Co., located in Peñuelas, Puerto Rico. Commercial operation began in March 2000. EcoEléctrica supplies approximately 15% of Puerto Rico's electricity. Gas for EcoEléctrica is provided through the Peñuelas LNG import terminal, which has been operating since 2000. Currently, this is the only LNG terminal on the island with the capability to import, store, regasify, and export natural gas. The Peñuelas LNG import terminal is owned by Naturgy.

The EcoEléctrica plant consumes approximately 93 million cubic feet (MMcf) of gas per day. EcoEléctrica also delivers 186 MMcf of regasified LNG to Costa Sur through a renegotiated gas supply agreement. The LNG terminal's capacity could be further expanded by an additional 93 MMcf by putting a fourth gasifier into service. However, a major increase in the terminal's capacity could require modifications, possibly including a second LNG storage tank. The site has space for a second storage tank but permitting would be required for its construction.

The EcoEléctrica plant is one of the most reliable, lowest cost, and efficient generators in Puerto Rico. Historically, the facility has had an availability factor higher than 90% and a capacity factor of approximately 76%. Note that under the existing contract, if PREPA dispatches EcoEléctrica at capacity factors higher than 76%, PREPA must pay a higher fuel cost for any generation above the 76% threshold. For this reason, at times when EcoEléctrica's capacity factor goes above 76% it has, on occasion, been more economical for PREPA to dispatch other facilities even though EcoEléctrica was more efficient. To illustrate EcoEléctrica's efficiency compared to other facilities on the island, Figure 1-1 is provided.

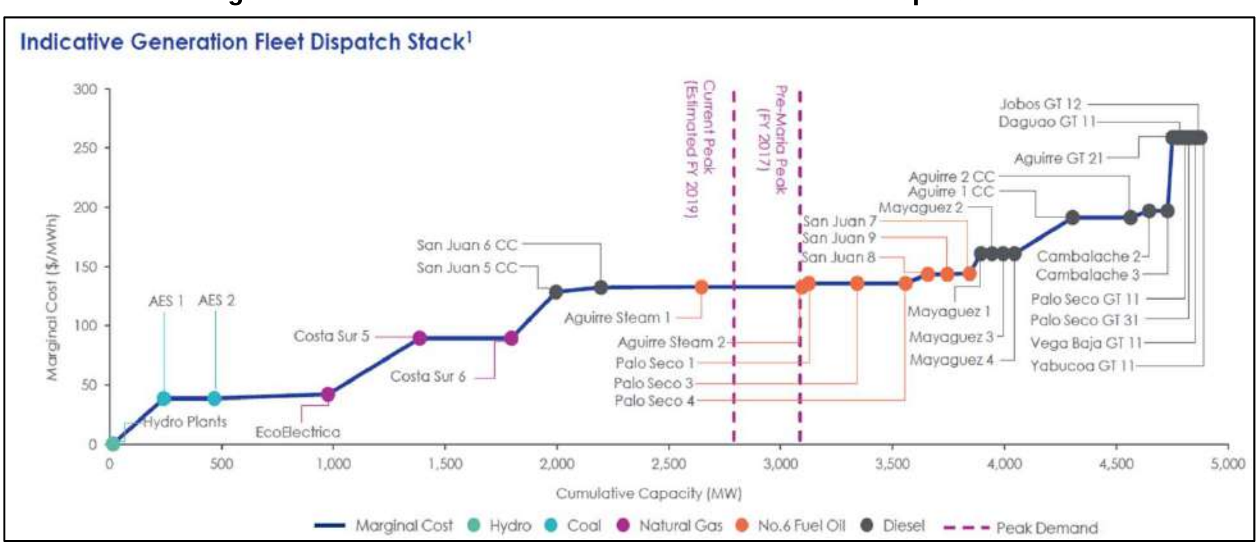
It should be noted that EcoEléctrica has historically seen minimal historical degradation in its heat rate. The heat rate of the original facility was approximately 7,500 Btu/kWh and today, 20 years later, the heat rate has only risen to 7,671 Btu/kWh. This minimal degradation in heat rate is an indication of how well the facility has been maintained since it first began operation, in addition to upgrades that have been made to the facility to improve efficiency. We have every indication that the facility will continue to be maintained at a high level going forward.

Figure 1-1 — Historic Heat Rate Comparison of Various Generators in Puerto Rico



EcoEléctrica's high efficiency and the relatively low cost for natural gas as compared to other fuels make EcoEléctrica one of the cheapest generator's for PREPA to dispatch. Figure 1-2 provides an estimate of the marginal cost of different generators on the island. Generators on the lower left have the lowest costs and should theoretically be dispatched first in a scenario where economics were the only dispatch consideration. Generators to the right have higher marginal costs and, from an economic perspective, should only be dispatched as the electricity demand rises enough to require their operation. EcoEléctrica is at the bottom left, indicating that it is one of the lowest cost generators to operate in Puerto Rico.

Figure 1-2 —Puerto Rico Indicative Generation Fleet Dispatch Stack



PREPA's Costa Sur Power Plant is an 820-megawatt facility located adjacent to EcoEléctrica that began commercial operation in the late 1960s. Costa Sur is currently the only PREPA-owned facility capable of firing natural gas. PREPA entered into a Gas Sales Agreement (GSA) with Naturgy for the supply of natural gas to Costa Sur Units 5 and 6 in 2012. Naturgy supplies natural gas to Costa Sur via a short pipeline from EcoEléctrica. As of May 2018, Costa Sur has been burning exclusively natural gas.

2. CONTRACT DISCUSSION

2.1 ORIGINAL CONTRACTS

2.1.1 EcoEléctrica Power Purchase and Operating Agreement

EcoEléctrica first entered into a Power Purchase and Operating Agreement (PPOA) with PREPA in 1995. The original contract was structured such that payments to EcoEléctrica were split between a fixed capacity payment and a variable energy payment. The capacity payment was originally meant to help pay for the facility's operating expenses, capital expenditures, original construction loan debt (which has been paid in full), and other related items. Meanwhile, the variable energy payment was structured to cover EcoEléctrica's fuel expenses. Under the existing contract, EcoEléctrica buys gas from Naturgy and is reimbursed by PREPA through the energy payment. The key terms of the existing PPOA are summarized below.

- Contract term ends on March 31, 2022
- Contract payment structure: Total Payment = Capacity Payment + Energy Payment
- The capacity payment amount is equal to approximately $230 million annually (2019 dollars)
- Maximum annual starts are set at 50 per year
- The maximum dispatch level of the plant is set at 76%. As previously mentioned, generation produced above this level incurs a higher fuel price that results in a higher energy payment (approximately 80% higher)
- Availability adjustment: the following availability adjustments apply based on EcoEléctrica's equivalent availability factor (EAF) for the rolling period comprising the last twelve billing periods. This availability adjustment is multiplied with the base monthly capacity payment. For months where EcoEléctrica has low availability, the result is that the facility is penalized through a reduced capacity payment.

Table 2-1 — Equivalent Availability Adjustment Factor

Range					Equivalent Availability Adjustment Factor (or EAAF)
		EAF	≥	93%	101%
93%	>	EAF	≥	89%	101% - ((93%-EAF) x 1.25)
89%	>	EAF	≥	86%	96% - ((89%-EAF) x 1.5)
86%	>	EAF	≥	71%	91.5% - ((86%-EAF) x 2)
71%	>	EAF	≥	61%	61.5% - ((71%-EAF) x 3)
61%	>	EAF			0%

2.1.2 Natural Gas Sales and Purchase Agreement

PREPA first entered into a natural gas sale and purchase agreement with Gas Natural Aprovisionamientos SDG S.A. (now Naturgy) for the supply of natural gas to Costa Sur Units 5 and 6 on March 28, 2012[1]. The agreement was amended three times (10 March 2014, 11 May 2015, and 16 August 2017). Key terms of the Agreement are summarized below.

- Contract term ends on December 31, 2020
- Maximum annual contracted quantity (Max ACQ): 72 TBtu
- Minimum annual contracted quantity (Min ACQ): 45 TBtu
- Pricing formula: the price for delivered natural gas is equal to the lesser of the two equations below

Equation 1: $(F_{\#61-11} + 1.29) \cdot HRN_F$

Equation 2: $\left[\frac{(0.1215 \cdot F_{\#6603} + 1.125)}{2} + \frac{(1.15 \cdot HH + 5.95)}{2}\right] \cdot HRN_F$

Where:

$F_{\#61-11}$ Unweighted average for relevant month of New York No. 6 Fuel Oil Cargo Price in Platt's ($/MMBtu)

$F_{\#6603}$ 6-month prior unweighted average of New York No. 6 Fuel Oil Cargo Price in Platt's ($/bbl)

HH Final settlement price of the Henry Hub natural gas futures ($/MMBtu)

HRN_F Heat rate normalization factor, a constant equal to 0.97

2.2 RENEGOTIATED CONTRACTS

EcoEléctrica and Naturgy pursued renegotiations aiming to separate current capacity and energy payments into two contracts. Capacity payments are established under an amended and restated PPOA with EcoEléctrica, while the current energy payment in the existing PPOA changes to a direct fuel payment through the amended Gas Sales Agreement (GSA) between PREPA and Naturgy. This amended GSA now covers the supply of natural gas to both EcoEléctrica and PREPA's adjacent Costa Sur facility.

[1] http://energia.pr.gov/wp-content/uploads/2018/08/Memorial-Explicativo-R-del-S-219-CEPR.pdf

2.2.1 Proposed Amended and Restated PPOA Terms

The key differences between the existing PPOA and the proposed amended terms are shown in the table below.

Table 2-2 — Comparison of Existing and Proposed PPOA Terms

	Existing PPOA	Proposed Amended PPOA	Notes
Contract Term	March 2022	September 2032	Additional 10 years
Nature of Contract	PREPA to purchase dependable generation capacity and electricity produced by EcoEléctrica	PREPA to pay EcoEléctrica a monthly capacity payment for the plant being available for electric generation	PREPA will be responsible for delivering natural gas to EcoEléctrica (see Section 2.2.2)
Contract Payment Structure	Capacity Payment + Energy Payment	Capacity Payment	Energy Payment to be replaced by direct fuel payment in GSA with Naturgy (see Section 2.2.2)
Capacity Payment Amount	$230 M per year at 507 MW (corresponding to $241 M per year at 530 MW)	$128 M per year at 530 MW (subject to an availability adjustment)	Annual discount of $113 million (subject to an availability adjustment)
Energy Payment	Compensation for net electrical output of the facility to cover fuel expenses. Average of 5.6 cents/kWh per year. Above a 76% capacity factor fuel costs increase approximately 80% higher	Replaced by direct fuel payments. Estimated to be 7.1 cents per kWh per year	Fuel payments will be made to Naturgy under the amended GSA
Availability Adjustment	As shown in Table 2-1	An additional availability bonus was introduced for monthly EAF greater than 93%	Bonus is 0% at 93% EAF and 29% at 95% EAF or above. Bonus increases linearly between 93% and 95% EAF
Maximum / Minimum Dispatch Level	Set at 54% and 76% of available capacity. Above a 76% capacity factor, fuel costs increase to 'spot price', approximately 80% higher.	Levels have been removed	PREPA can now dispatch EcoEléctrica beyond a 76% capacity factor without incurring higher fuel costs for that additional generation
Maximum Start-ups	Limit of 50 starts per year	This number will be increased to a level to be agreed upon by both parties	PREPA will have more flexibility to use EcoEléctrica as a cycling facility going forward
Start-up Costs	PREPA pays EcoEléctrica's start-up costs until the units synchronize to the grid	Start-up payment terms will remain unchanged; however, EcoEléctrica will reimburse PREPA for fuel costs associated with start-up	This arrangement is consistent with the separation of the previous contract into a separate PPOA and GSA

Note: All dollar values above are in 2019 dollars

Select terms of the renegotiated PPOA with EcoEléctrica are further summarized as follows:

Payment Structure:

- Given the tolling nature of the Amended & Restated PPOA, the structure of the Energy Payment will be removed.
- Naturgy, PREPA's natural gas supplier, will enter into an LNG tolling services agreement with EcoEléctrica and will deliver natural gas to the EcoEléctrica and Costa Sur plants.
- Performance tests of the EcoEléctrica plant will be performed at the start of the new contract and immediately after the completion of each major maintenance cycle of the gas turbines and steam turbine. These tests will be paid for by EcoEléctrica. The performance tests will be used to establish EcoEléctrica's guaranteed heat rate curves. These curves will be used to determine how much PREPA will pay Naturgy for the fuel that EcoEléctrica consumes. If EcoEléctrica consumes more gas than it should for a given output level, Naturgy will bear the cost of such excess gas. Similarly, if EcoEléctrica consumes less gas than the plant heat rate curves suggest it should have, PREPA will compensate for that difference. This payment mechanism is common in the energy industry.
- The schedule for major maintenance and hot gas inspection cycles will follow the Original Equipment Manufacturer service bulletins and will be agreed upon by PREPA and EcoEléctrica. Allowing PREPA the right to agree on the EcoEléctrica maintenance schedule helps protect PREPA financially from EcoEléctrica setting a maintenance schedule that unfairly aims to take advantage of the availability bonus mechanism.

Availability Adjustment:

- For any period in which the plant's Equivalent Availability Factor (EAF) exceeds 93%, EcoEléctrica will obtain a bonus payment, which will be based off a percentage of the fixed capacity payment. The percentage will be a value that linearly increases from 0% to 29% for values between 93% and 95% EAF and remains constant for EAF values greater than 95%. Section 3.2 quantifies the results of various bonus scenarios depending on plant performance.
- The bonus structure offers a significant incentive for EcoEléctrica to continue to maintain the facility and achieve high availability into the future.
- PREPA has negotiated a set maintenance schedule into the PPOA. This helps to keep EcoEléctrica from taking advantage of the bonus mechanism by holding EcoEléctrica to specific outage time periods.

Force Majeure:

- The Force Majeure clauses will be modified to define a "Grid Force Majeure Event" which could be triggered by damages to PREPA's grid system caused by severe atmospheric events.

- A Grid Force Majeure Event provides PREPA protection in the case that EcoEléctrica is available for dispatch but PREPA's grid is not restored, for example, following a major hurricane.

2.2.2 Proposed Amended GSA Terms

The key differences between the existing GSA and the proposed amended terms are shown in the table below.

Table 2-3 — Comparison of Existing and Proposed GSA Terms

	Existing GSA	Proposed Amended GSA	Notes
Contract Term	December 2020	September 2032	Term is consistent with proposed amended PPOA
Facilities Covered	Costa Sur	Costa Sur and EcoEléctrica	Naturgy to install an additional meter at the EcoEléctrica plant to allow measurement of gas deliveries to PREPA
Pricing Formula	As shown in Section 2.1.2, pricing currently considers the price of No. 6 fuel oil and the price of natural gas	Price based solely on price of natural gas and natural gas price adder reduced by 8% (see Table 2-4)	Removing the hedge to fuel oil is forecasted to result in savings to PREPA (see Section 3.3). Additional discussion below.
Minimum Annual Contract Quantity	45 TBtu (Costa Sur only)	55 TBtu (Costa Sur and EcoEléctrica combined) with flexibility to be reduced under certain scenarios.	See below for summary of quantity flexibility

Select terms of the renegotiated GSA with Naturgy are further summarized below:

Minimum/Maximum Gas Quantities:

The Minimum Annual Contract Quantity (Min ACQ) is set at 55 TBtu. However, PREPA can reduce the minimum quantity to a value between 55 TBtu and 19 TBtu if either unit 5 or 6 of Costa Sur is retired. PREPA can also reduce the minimum quantity to a value between 55 TBtu and 12 TBtu if electricity demand in Puerto Rico falls below 2,300 MW (peak demand) or installed renewable generation exceeds 15% of the total power generated on the grid (MWh) after January 1, 2024. All three of these provisions are unique options that PREPA can choose to exercise or not. These options give PREPA flexibility to avoid take or pay liabilities as PREPA continues to modernize its grid and generators. The Maximum Annual Contract (Max ACQ) quantity is equal to 106 TBtu. If PREPA elects to reduce their Min ACQ, the Max ACQ is set equal to 120% of the Min ACQ. PREPA also has the option to undo the reduction in the Min ACQ (and thus the Max ACQ) one time over the contract.

Pricing Formula:

As described in Table 2-3, the new natural gas pricing structure in the GSA removes the hedge to fuel oil No. 6, which is expected to result in savings for PREPA. The new formula for natural gas in the proposed GSA is provided below:

$$Fuel\ Price\ (\$/MMBtu) = 1.15 \cdot HH + \text{Adder}$$

Where:

HH Final settlement price of the Henry Hub natural gas futures ($/MMBtu)

$Adder$ The adder is equal to the following:

This equation would apply to fuel purchased for both EcoEléctrica and Costa Sur.

Table 2-4 — Proposed GSA Adder Fees

Dates	Adder ($/MMBtu)
Start of Contract – December 31, 2020	$5.80
January 1, 2021 – December 31, 2021	$5.70
January 1, 2022 – December 31, 2022	$5.60
January 1, 2023 – September 30, 2032	$5.50

If Puerto Rico is granted a Jones Act waiver for LNG imports, Naturgy would drop the adder down to $4.80/MMBtu.

3. FINANCIAL DISCUSSION

3.1 MODELING INPUTS AND ASSUMPTIONS

Sargent & Lundy modeled the financial implications of the proposed contracts with both EcoEléctrica and Naturgy. The model accounts for the key contractual terms discussed in the previous section.

Our financial analysis also made several financial and technical assumptions. These are provided below:

- EcoEléctrica would operate at an 84% capacity factor, per PREPA's input. This is approximately 10% higher than the historical capacity factor; however, increased fuel costs for capacity factors above 76% in the current contract are removed in the proposed contract. Thus, PREPA has the option to dispatch the facility more without the previous financial consequences.
- The annual capacity payment in the current contract is equal to $230 million dollars (507 MW). Since the available capacity of the facility has increased from 507 MW to 530 MW, this payment would correspond to $241 million dollars at 530 MW.
- Various future rolling EAF (availability) levels were investigated to assess the impact of the availability bonus for different operating scenarios.
- The current heat rate of EcoEléctrica is set at 7,671 Btu/kWh and degrades by 0.25% annually. This heat rate is consistent with what is contracted in the amended PPOA. The degradation factor was estimated based on EcoEléctrica's actual historical operational data.
- The Henry Hub natural gas price forecast was taken from the most recent IRP forecasts for natural gas prices.
- Inflation was set at 2% going forward. For the purposes of adjusting historical capacity and energy payments to 2019 dollars, historical CPI data from the Bureau of Labor Statistics (BLS) was used.
- Taxes were not included, per the guidance of PREPA.

3.2 ECOELÉCTRICA FINANCIAL ANALYSIS

3.2.1 Sensitivity Analysis Scenarios

Sargent & Lundy investigated two different financial scenarios using the inputs and modeling assumptions listed above. Both scenarios are based on a specific forecasted rolling equivalent availability factor (rolling EAF), and thus availability bonus achieved by EcoEléctrica. The different scenarios are described below:

1. Expected Future EAF Level – This scenario considers historical facility availability, EcoEléctrica's own monthly EAF forecast, and our assessment of EcoEléctrica's ability to achieve high future availability based on our visits to the plant and meetings with plant staff. This scenario results in an average capacity payment that is 115% of the annual base capacity payment. Two sub-cases were tested under this expected future EAF level scenario: Scenario 1A and 1B. Scenario 1A uses an 84% capacity factor. Scenario 1B uses a 60% capacity factor.

2. Low Future EAF Level – This scenario is based off the monthly EAF forecast provided by EcoEléctrica. In our opinion, EcoEléctrica had an incentive to provide an availability forecast that appears lower than what is likely to take place. This incentive is rooted in the fact that EcoEléctrica wanted to demonstrate during negotiations that the availability bonus was going to have minimal financial impact, as the inclusion of a bonus was a key discussion topic between the parties. Through our independent analysis and visits to the EcoEléctrica facility, Sargent & Lundy is of the opinion that EcoEléctrica is more than capable of surpassing the availability forecast that it provided to PREPA. Thus, Sargent & Lundy considered this scenario to be representative of a low future EAF. This scenario results in an average capacity payment that is 110.9% of the annual base capacity payment.

3.2.2 Financial Analysis Results

The results of the financial analysis are presented in the following section for each scenario investigated. Note that all values are presented in 2019 dollars. Additionally, the following table summarizes the results for each scenario. Historical data from ten years (2009 to 2018) is also provided for comparison purposes.

Table 3-1 — Comparison of Financial Scenario Results

	Average Capacity Payment	Capacity Factor	Annual Capacity Payment	Annual Fuel (or Energy) Payment	Total Annual Payment
Scenario 1A - Expected Future Availability (EAF) (530 MW)	115% of Base Capacity Payment	84%	$148.1 M	$267.7 M	$415.8 M
Scenario 1B - Expected EAF, Low Capacity Factor (530 MW)	115% of Base Capacity Payment	60%	$148.1 M	$191.1 M	$339.2 M
Scenario 2 - Low Future EAF (EcoEléctrica's Forecast) (530 MW)	110.9% of Base Capacity Payment	84%	$142.9 M	$267.7 M	$410.6 M
Current Contract, Historical Averages 2009-2018 (507 MW)	-	75%	$230.2 M	$186.7 M	$416.9 M

3.2.2.1 Scenario 1A: Expected Future EAF Level

Capacity Payments (Scenario 1A)

The forecasted EAF over the lifetime of the contract for this scenario results in an average capacity payment equal to 115% of the annual base capacity payment. This corresponds to a payment equal to approximately $148.1 million annually.

Fuel Payments (Scenario 1A)

Fuel payments vary annually due to changes in the Henry Hub forecast for natural gas; however, average fuel payments total $267.7 million annually. Note that the increase in fuel costs is partially a result of the fact that the new contract is based on a higher available capacity (530 MW versus 507 MW).

Combined Payments (Scenario 1A)

Combined capacity and fuel payments average to $415.8 million annually. At an 84% facility capacity factor, total energy production is forecasted to be 3.90 million MWh. Based on this generation level, contract costs can be broken down further as follows:

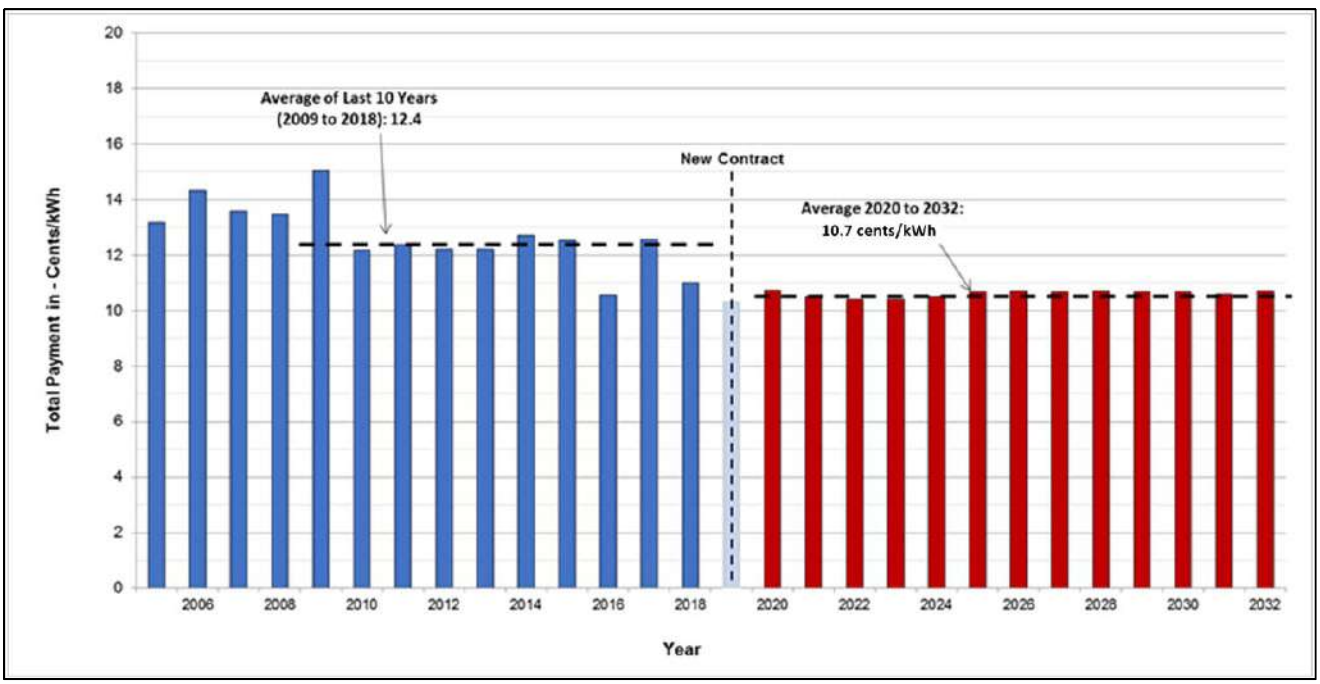
Capacity: 3.8 cents/kWh
Fuel: 6.9cents/kWh
Total: 10.7 cents/kWh

For comparison, historical payments to EcoEléctrica (between 2009 and 2018) can be broken down into the following categories (all numbers adjusted to 2019 dollars). Note the historical capacity factor has been 75%.

Capacity: 6.8 cents/kWh
Energy: 5.6 cents/kWh
Total: 12.4 cents/kWh

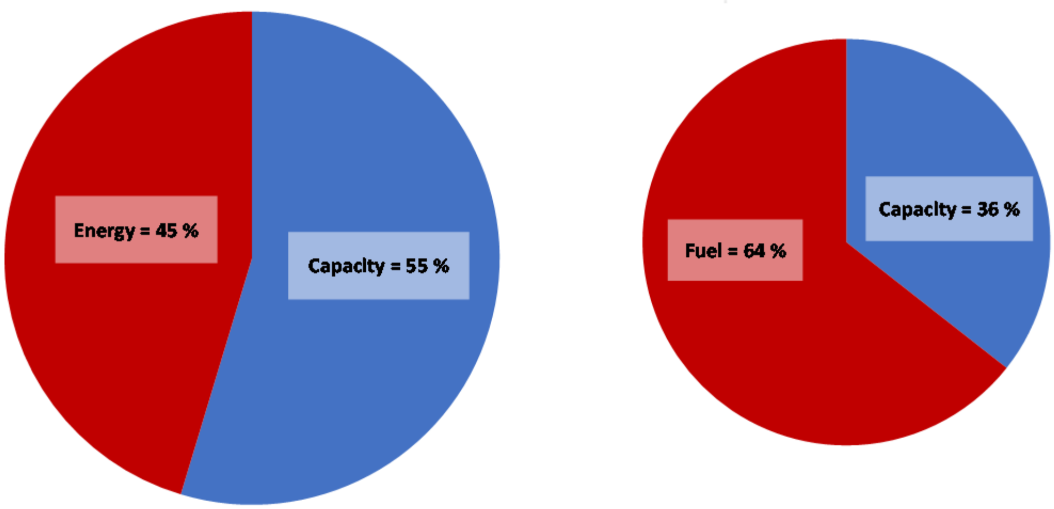
Thus, for this scenario the expected reduction in payments to EcoEléctrica/Naturgy is equal to 1.8 cents/kWh. This can also be seen by looking at the historical payments to EcoEléctrica, as shown below (all values are in 2019 dollars):

Figure 3-1 — Scenario 1A Combined Payments per kWh, Historical Comparison



The historical to forecasted breakdown between capacity payments and energy/fuel payments is provided in the following figure. The proposed contract fundamentally changes the financial breakdown of the total payment from being primarily devoted to the capacity payments (historically accounting for 55% of the total payments) to primarily devoted to the fuel payments (accounting for 64% of the total payments in the renegotiated structure). As more renewable generation is installed on the Puerto Rican grid, we are of the opinion that the forecasted payment breakdown (lower fixed capacity payment and varying fuel payment based on generation) is better for PREPA financially given the fact that EcoEléctrica could start transitioning to a cycling facility during the daytime (to offset the intermittent nature of renewable generation). This is discussed further in the next section.

Figure 3-2 — Scenario 1A Breakdown of Payments



3.2.2.2 Scenario 1B: Expected Future EAF Level, Lower Capacity Factor Sensitivity Case

As more renewable generation is introduced on the grid, there is the potential that EcoEléctrica transitions from a pure baseload generator to a facility that provides baseload power at night, along with grid stability (cycling operation) services during daytime. As this transition occurs, it is likely that the overall capacity factor of EcoEléctrica will fall from the modeled 84%. To assess the financial impact of this situation, we modeled a separate scenario where the EcoEléctrica capacity factor was equal to 60%.

The results of this analysis are provided as follows:

Capacity Payments (Scenario 1B - Lower Capacity Factor)

The average capacity payment is equal to 115%, consistent with Scenario 1A. The total annual payment is unchanged at $148.1 million annually.

Fuel Payments (Scenario 1B - Lower Capacity Factor)

Since the modeled capacity factor is reduced from 84% down to 60%, fuel payments fall substantially. Average fuel payments total $191.1 million annually (this is down from $267.7 million annually if the facility's capacity factor was 84% as in Scenario 1A).

Combined Payments (Scenario 1B - Lower Capacity Factor)

Combined capacity and fuel payments average to $339.2 million annually. At a 60% facility capacity factor, total energy production is forecasted to be 2.79 million MWh. Based on this generation level, contract costs can be broken down further as follows:

Capacity:	5.3 cents/kWh
Fuel:	6.9 cents/kWh
Total:	**12.2 cents/kWh**

Since a greater proportion of the total payments go to the variable fuel costs (rather than the fixed capacity payment), overall costs to PREPA fall significantly as facility generation falls (the facility burns less fuel as generation falls). For this reason, we are of the opinion that the proposed contracts' payment mechanisms better align with PREPA's long-term renewable goals. In contrast, under the existing contract, PREPA would be paying a larger fixed capacity payment regardless of whether the facility was dispatched at a high capacity factor or not. Thus, costs on a cents per kWh basis would rise significantly under the existing contract as EcoEléctrica transitioned to a daytime cycling facility.

It should also be noted that the value of ancillary services is not factored into this analysis. We are of the opinion that as EcoEléctrica starts to transition to a cycling facility, EcoEléctrica would provide more value to the grid (in the form of ancillary services) than the analysis above quantifies. The exact dollar amount of additional value is not known; however, ancillary service auctions in deregulated energy markets around the globe have demonstrated that this value can be substantial.

3.2.2.3 Scenario 2: Low Future EAF Level

Capacity Payments (Scenario 2)

The forecasted EAF over the lifetime of the contract for this scenario results in an average capacity payment equal to 110.9% of the annual base capacity payment. This corresponds to a payment equal to approximately $142.9 million annually.

Fuel Payments (Scenario 2)

Fuel payments are unchanged from Scenario 1A. Average fuel payments total $267.7 million annually.

Combined Payments (Scenario 2)

Combined capacity and fuel payments average to $410.6 million annually. Based on 3.90 million MWh of generation at an 84% facility capacity factor, contract costs can be broken down further as follows:

Capacity:	3.7 cents/kWh
Fuel:	6.9 cents/kWh
Total:	**10.7 cents/kWh**

3.3 COSTA SUR FINANCIAL ANALYSIS

The renegotiated contracts result in savings for Costa Sur solely from the cost of fuel. As shown in Section 2.1.2, the current pricing structure of delivered natural gas to Costa Sur incorporates price indices for No. 6 fuel oil to serve as a ceiling, or hedge, against the fluctuations of natural gas prices. The new proposed pricing formula eliminates any ties to No. 6 fuel oil and sets the price strictly based on the market price of natural gas. The price for natural gas will now be calculated as follows:

$$Natural\ Gas\ Price\ per\ MMBtu\ = 115\% \cdot Henry\ Hub\ Price + Adder$$

The adder is set at $5.80 per MMBtu for 2019 and 2020, $5.70 for 2021, $5.60 for 2022, and $5.50 for 2023 through the end of the term.

For the past several years, the Henry Hub price for gas has been lower than market prices for No. 6 fuel oil on a dollar per MMBtu basis. This trend is forecasted to continue. Thus, it is likely that PREPA will benefit from lower fuel costs as a result of the change in the pricing formula.

The spread between fuel oil and natural gas prices is forecasted to widen over the length of the contract. Our calculations indicate that average savings of over $29.1 million annually could be possible over the term of the contract (assuming a 60% capacity factor per the PREPA Dispatch Center's recommendations). Current fuel commodity forecasts indicate that these savings are expected to be modest over the first 5 years (averaging approximately $10 million per year) and increase in the future. Note that it is challenging to forecast fuel prices with any degree of accuracy beyond a few of years. Based on this consideration, the $29.1 million annual long-term savings estimate should be used with an understanding that the value has a high degree of uncertainty and can vary going forward. Regardless of how PREPA operates the Costa Sur plant, fuel commodity price forecasts indicate that PREPA can obtain fuel savings due to the removal of the hedge to fuel oil in the pricing formula of the proposed GSA.

3.4 OVERALL SAVINGS CALCULATIONS

We estimate that the terms of the proposed amendments would amount to savings for PREPA of approximately $100 million per year, of which $71 million are derived from EcoEléctrica and $29 million are derived from Costa Sur. Savings tied to Costa Sur are expected to be modest over the first five years, averaging approximately $10 million per year. Given this, total savings are expected to be approximately $81 million per year over the next five years. Note that these savings figures meet the Fiscal Plan's savings target of $80 million assigned to the renegotiation of existing PPOAs. We break total savings into three sources, as is discussed as follows:

1) *Contractual savings associated with the changing capacity and fuel payment*

The combined charges for EcoEléctrica are reduced. PREPA negotiated a reduction in the capacity payment equal to $108 million annually (offset by an availability bonus). However, these savings are partially offset by increased fuel costs. We estimate the net reduction corresponds to approximately $35 million annually in savings for PREPA. This value is calculated by comparing expected payments under each contract structure at the historical average generation level of 3.33 million MWh (a 75% capacity factor). Note that since the available capacity increases from 507 MW to 530 MW in the new contract, this generation level corresponds to two different capacity factors for each contract, 75% for 507 MW (existing contract) and 71.7% for 530 MW (proposed contract). The total calculated cost for each contract structure is shown below:

Table 3-2 — Comparison of Existing and Proposed Contract Costs

	Existing Contract Structure	Proposed Contract Structure
Generation (MWh)	3,330,452	
Available Capacity (MW)	507 MW	530 MW
Capacity Factor	75.0%	71.7%
Capacity Payment (cents/kWh)	$225.0 M	$148.1 M[1]
Total Fuel Payment (cents/kWh)	$186.7 M	$228.6 M
Total Payment (Million USD)	$411.7 M	$376.7 M
Difference (Million USD)	**$35.0 M**	

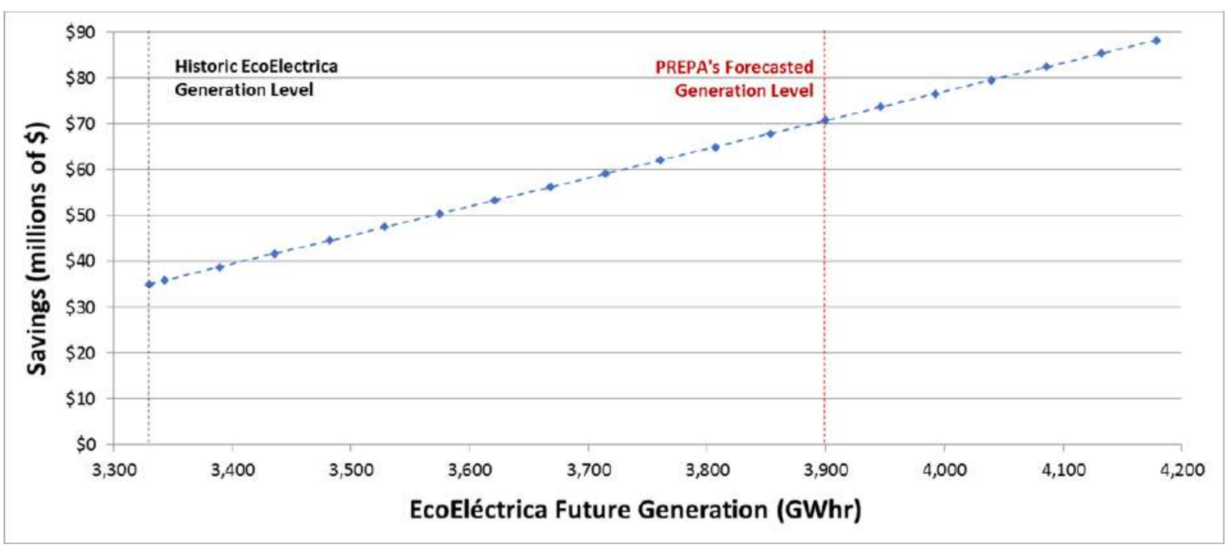
1) Capacity payment includes discount, offset by the estimated availability bonus

2) *Dispatch savings derived from increasing EcoEléctrica's dispatch level*

Under the existing contract, if PREPA dispatches EcoEléctrica at capacity factors higher than 76%, PREPA must pay a higher fuel cost for generation above the 76% threshold. The specific cost of this additional fuel varies based on both market conditions and Naturgy's internal costs, but the most recent IRP lists this cost ($ per MMBtu) at approximately 80% higher than the contracted fuel cost. For this reason, at times when EcoEléctrica's capacity factor would go above 76%, PREPA sometimes chooses to dispatch other facilities instead of EcoEléctrica on the basis of economics. The proposed contract removes this feature. Going forward, PREPA would pay the same price per MMBtu of natural gas to dispatch EcoEléctrica, regardless of capacity factor. Given EcoEléctrica's high efficiency, it makes financial sense for PREPA to dispatch the facility as often as possible because additional generation from EcoEléctrica would reduce the generation needed from other more expensive facilities.

The PREPA Dispatch Center has indicated that they expect this change will allow PREPA to dispatch EcoEléctrica at an 84% capacity factor going forward. They also indicated that this generation is likely to come from the Aguirre steam facility. Increasing the generation of EcoEléctrica from 3.33 million MWh (corresponding to the average historic capacity factor of 75%) to 3.90 million MWh (corresponding to an 84% capacity factor) will cost PREPA and additional $39 million in natural gas costs. However, the additional 0.57 million MWh generated at EcoEléctrica will not be generated at Aguirre, which will save PREPA a total of $74 million in Aguirre's fuel expenses and just over $1 million in Aguirre's variable O&M costs, for a net total savings of $36 million annually. The following figure illustrates forecasted annual savings at various EcoEléctrica dispatch levels. Note that the point on the left corresponds to the $35 million figure from (1) above (contractual savings).

Figure 3-3 — Forecasted Savings for PREPA as a Function of EcoEléctrica Generation



3) *Costa Sur fuel savings from removing the fuel oil hedge in the fuel pricing formula and reducing the adder fee*

The change in the pricing formula for delivered natural gas at Costa Sur is expected to result in average savings of $29.1 million per year, with the majority of the savings coming later in the contract term. Savings over the first 5 years are not expected to average more than $10 million per year.

4. ALTERNATIVE OPTIONS TO CONTRACT RENEWAL

This section discusses alternatives to contract renewal. We consider two specific scenarios:

A) The proposed contracts with both EcoEléctrica and Naturgy are not pursued. PREPA plans on closing the EcoEléctrica facility following the end of the facility's PPOA in 2022. This scenario is considered in the IRP.

B) The proposed contracts with both EcoEléctrica and Naturgy are not pursued. Instead, PREPA pursues a legal strategy where they use Bankruptcy Code section 365(a), as incorporated into the Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA), to reject the existing PPOA and GSA with EcoEléctrica and Naturgy. The goal of this action would be to force EcoEléctrica and Naturgy to provide energy and gas at lower rates to PREPA.

4.1 SCENARIO A: CLOSURE OF ECOELÉCTRICA

In this scenario, the proposed contracts with EcoEléctrica and Naturgy are not accepted and PREPA decides to close the facility following the end of its existing PPOA in 2022. This scenario is considered in the IRP. The IRP suggests that following the closure of EcoEléctrica, a new combined cycle would be built at Costa Sur to replace the lost generation from EcoEléctrica. It is our opinion that PREPA would be faced with several significant challenges under this scenario, as are discussed below:

1. If PREPA does not renegotiate and extend the current GSA, which ends in December 2020, Naturgy could charge PREPA a higher price for natural gas. We estimate that starting in 2021 (after expiration of the current GSA) and up until when a new combined cycle is built, Naturgy could charge PREPA up to 25% more for natural gas to the existing Costa Sur facility. The 25% increase would make the cost of natural gas equal to the cost of bunker fuel oil, the alternative fuel for Costa Sur. This could cost PREPA an additionally $140 million dollars in fuel costs for Costa Sur annual. Note that this scenario is not without precedence as a similar situation transpired earlier this year with diesel fuel.

   There is also the potential that the Peñuelas LNG terminal shuts down following the closure of EcoEléctrica, because the terminal requires operation of the EcoEléctrica plant for it to operate. Operation of the terminal without operation of the plant is not possible without modifications to the terminal. In either case, if the terminal is unavailable, there would likely not be another means for PREPA to obtain natural gas at Costa Sur. In this case, Costa Sur would be forced to burn bunker fuel, which would not only cost PREPA an additional $140 million annually, but could also put Costa Sur in violation of emissions regulations.

2. Legally, PREPA does not have access rights to the Peñuelas import terminal (Naturgy has exclusive rights to this facility). Thus, PREPA would be forced to continue to pay for use of the import terminal, regardless of who supplies LNG to PREPA. Given the high cost of constructing another LNG import terminal (page 7-10 of the 2019 IRP estimates this cost to be approximately $600M, or $2.1M per MMSCFD * 93 MMSCFD per vaporizer * 3 vaporizers), Naturgy would have substantial leverage in this negotiation. Additionally, maritime constraints tied to the Jones Act further limit PREPA's ability to cost effectively move gas from one place to another. The option of building pipelines to transport natural gas from other areas on the island is opposed by the public and the option of using trucks to deliver LNG is both expensive and challenging given the volume of LNG needed at the site on a daily basis (plus a vaporizing system would still be needed). Once a new facility is built, we consider that the upper limit of the price that PREPA could be charged for gas would be equal to the price of the replacement fuel that could be burned at the new facility, likely diesel fuel. The current and forecasted price of diesel fuel is substantially higher than the price for gas that has been negotiated with Naturgy under the proposed contract (approximately twice as high on a $/MMBtu basis).

   Currently, PREPA has leverage in the negotiation with Naturgy. Given that Naturgy is the majority shareholder of EcoEléctrica, the closure of EcoEléctrica would result in a substantial loss of capacity revenue for Naturgy. Additionally, closure of EcoEléctrica would also result in lost natural gas revenues to Naturgy. This negotiating leverage is lost in the event that PREPA closes EcoEléctrica.

   It should be noted that the IRP analysis comparing the EcoEléctrica facility to a new combined cycle at Costa Sur is rooted in a comparison of the technical differences between the power plants and does not get into all legal details (such as terminal rights) or technical details (such as potential modifications) associated with the LNG terminal. However, these details significantly complicate the scenario of closing and replacing EcoEléctrica.

3. Puerto Rico would lose one of its most inexpensive, most efficient, cleanest generating, base load power plants. EcoEléctrica is one of the few plants that currently aligns with PREPA's vision for the future: low cost, clean, reliable generation.

4. If PREPA were to not renew the contract with EcoEléctrica, over 15% of the island's baseload generation would have to be replaced. A new combined cycle at Costa Sur, or another facility elsewhere, would eventually be able to replace EcoEléctrica's generation; however, given that the EcoEléctrica contract expires in 2022, it is unlikely that a new facility could be built in time. The IRP estimates that the soonest a new replacement facility could be operational (due to the time required for environmental studies and approval, governmental permitting, design, and construction) is 2025. For that reason, PREPA would have to find over 500 MW of generation to bridge the gap between the end of EcoEléctrica's contract in 2022 and when a new facility would be completed in 2025. Given PREPA's aging generation fleet and grid limitations, it will be challenging for PREPA to bridge this gap. Even if solar generation is constructed at a rapid pace, the low capacity factor and intermittent nature of solar power (zero production at night and minute-by-minute variation due to cloud cover, weather, etc.) is unlikely to be a suitable replacement for EcoEléctrica until a new facility can be built.

   Instead, it is likely that PREPA would have to increase dispatch of other existing, inefficient generators that burn more expensive diesel and bunker fuel. For reference, Aguirre's oil-fired generators, units that would likely have to make up for EcoEléctrica's lost generation, have a 35% higher heat rate than EcoEléctrica and burn bunker fuel oil, which is 25% more expensive (on a MMBtu basis) than the negotiated natural gas price with Naturgy. Each MWh produced at Aguirre is approximately 70% more expensive in fuel costs than a MWh produced at EcoEléctrica. The increased fuel costs to PREPA could easily climb to over $100 million annually before a replacement facility is available.

5. As described previously, the negotiation with EcoEléctrica/Naturgy has the potential to reduce the cost of electricity for Puerto Rican ratepayers immediately. While the exact amount of savings depends upon how PREPA chooses to dispatch the facility and how well EcoEléctrica performs going forward, our financial calculations indicate that PREPA could save approximately $100 million annually, or $81 million per year over the next five years. These savings are described further in Section 3.4.

While PREPA could in theory replace EcoEléctrica's generation if a new contract was not pursued, not extending the EcoEléctrica PPOA would place PREPA in a challenging and potentially very expensive position with few ideal solutions.

4.2 SCENARIO B: LEGAL STRATEGY AGAINST ECOELÉCTRICA AND NATURGY

Under this strategy, PREPA would not pursue finalizing the renegotiated contracts. Instead, PREPA would reject one or both existing contracts (EcoEléctrica PPOA and/or Naturgy GSA). The goal of this legal action would be to force better financial terms for PREPA. A further discussion of this process, and our team's associated analysis, is provided below:

1. PREPA has the right to reject the GSA and the PPOA.
    a. Bankruptcy Code section 365(a), as incorporated into the Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA), provides that PREPA, subject to the court's approval, may assume or reject any executory contract, which includes the GSA and PPOA. While the Federal Energy Regulatory Commission (FERC) has at times argued, and courts have occasionally held, that regulatory obligations arising out of power sales contracts cannot be rejected without FERC approval, the absence of settled case law directly on point addressing the Public Utility Regulatory Policies Act of 1978 (PURPA), coupled with the intrastate nature of the PPOA, support our view that these arguments would not prevail in or as to Puerto Rico.
    b. PREPA can reject the PPOA or GSA at any time before confirmation of the plan of adjustment under PROMESA.
    c. Rejection by PREPA would constitute a breach of the contract and that gives the counterparty a claim for any damages or loss suffered as a result of the rejection (e.g., take-or-pay payments, damages specified in the contracts). The counterparty may recover these damages, usually for pennies on the dollar, as PREPA emerges from bankruptcy.
2. Rejection of the GSA may result in worse outcomes for PREPA
    a. Naturgy has exclusive control over the capacity of the Peñuelas regasification facility to receive and vaporize LNG and re-deliver natural gas at any point in the relevant pipelines, including the Costa Sur and EcoEléctrica power plant. These pipelines constitute the only natural gas supply lines to either plant.
    b. If PREPA rejects the GSA in order to extract more concessions from Naturgy, Costa Sur will as a practical matter lose access to natural gas. Given Naturgy's ownership of the only gas facilities serving the plant, no other natural gas supplier will have the ability to deliver gas to the Costa Sur plant without Naturgy's consent. PREPA will have to pay a premium to secure such consent (and/or terminal use rights); burn back-up fuel in the plant (which may be practically and legally difficult given emissions limitations that may apply); and/or re-enter gas supply arrangements with Naturgy, likely at a much higher price.

3. Rejection of the PPOA could result in EcoEléctrica having the right to put its energy to PREPA at PREPA's avoided cost (the "PURPA Put") or potentially worse outcomes.

    a. PURPA requires electric utilities, unless exempted, to purchase energy and capacity from Qualifying Facilities (QFs). PREPA does not qualify as an exempt entity under PURPA, and as of February 2019, EcoEléctrica had QF status (though it had not recertified this status since 2005). This means, in the absence of a PPOA, PREPA likely still can be compelled under PURPA to buy EcoEléctrica's energy and/or capacity.

    b. Avenues to challenge EcoEléctrica's QF status may exist. FERC could revoke such status, for instance, if the facility no longer complies with certain operating and efficiency standards; no longer satisfies FERC's technical criteria for cogeneration; or fails to maintain up-to-date recertification of changes in facts regarding the facility's technical characteristics or its ownership.

    c. Assuming the PURPA Put applies, determination of the actual payment amounts would likely take some time (i.e. months), since the Puerto Rico Energy Bureau (PREB) has not yet established PREPA's avoided cost. This may place cash flow pressure on EcoEléctrica in the interim.

    d. As for the quantum of the payments QFs can demand through exercise of their PURPA Put rights, states/utilities use a handful of methods to calculate avoided costs, and generally have discretion in choosing how to do so. As one example, utilities have used the principle that the utility's purchase from QFs permit the utility to avoid its projected costs of building or buying the next block of generation that it requires to meet the requirements of its load plus reserves. PREPA has internally conducted studies of these costs, and there is evidence that they are substantially higher than the costs currently in the existing PPOA.

    e. Rejecting the PPOA could, however, result in an even worse outcome for PREPA if EcoEléctrica decided not to exercise its right to the PURPA Put and instead to mothball the facility until PREPA agreed to its pricing demands. According to EcoEléctrica, if it does not move LNG/natural gas through the regasification terminal, then the terminal lacks sufficient throughput on Costa Sur alone to maintain continuous operations. In a scenario where the EcoEléctrica plant shut down, PREPA could lose not only all of the electricity generated by EcoEléctrica, but also the electricity generated by the Costa Sur plant, unless PREPA burned back-up fuel at Costa Sur (which may be practically and legally difficult given emissions limitations that may apply). EcoEléctrica and Costa Sur provide just over 40% of the electricity for the island, and the current grid dynamics leave PREPA with little excess generation. Losing both plants would likely result in political and public backlash against PREPA, in addition to the obviously significant financial impact.

We view rejection of either contract as a high risk, uncertain reward tactic. Even if PREPA can find ways to undermine EcoEléctrica's status as a qualifying facility under PURPA, PREPA has very few alternatives from a fuel and/or electricity supply perspective to deal with the consequences if EcoEléctrica or Naturgy play hardball. Rejection appears more likely than not to produce significant harm in financial, political, and public perception terms.

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF PUERTO RICO

In re: THE FINANCIAL OVERSIGHT AND MANAGEMENT BOARD FOR PUERTO RICO, as representative of THE COMMONWEALTH OF PUERTO RICO, *et al.*, Debtors. [1]	PROMESA Title III Case No. 17 BK 3283-LTS (Jointly Administered)
In re: THE FINANCIAL OVERSIGHT AND MANAGEMENT BOARD FOR PUERTO RICO, as representative of PUERTO RICO ELECTRIC POWER AUTHORITY ("PREPA"), Debtor.	PROMESA Title III Case No. 17 BK 4780-LTS

PREPA'S OBJECTIONS AND RESPONSES TO UTIER'S DISCOVERY REQUEST PURSUANT TO ORDER ON MOTION FOR PROTECTIVE ORDER, DOCKET NO. 1995

[1] The Debtors in these Title III Cases, along with each Debtor's respective Title III case number and the last four (4) digits of each Debtor's federal tax identification number, as applicable, are the (i) Commonwealth of Puerto Rico ("Commonwealth") (Bankruptcy Case No. 17-BK-3283- LTS) (Last Four Digits of Federal Tax ID: 3481); (ii) Puerto Rico Sales Tax Financing Corporation ("COFINA") (Bankruptcy Case No. 17-BK-3284-LTS) (Last Four Digits of Federal Tax ID: 8474); (iii) Puerto Rico Highways and Transportation Authority ("HTA") (Bankruptcy Case No. 17-BK-3567-LTS) (Last Four Digits of Federal Tax ID: 3808); (iv) Employees Retirement System of the Government of the Commonwealth of Puerto Rico ("ERS") (Bankruptcy Case No. 17-BK-3566-LTS) (Last Four Digits of Federal Tax ID: 9686); (v) Puerto Rico Electric Power Authority ("PREPA") (Bankruptcy Case No. 17- BK-4780-LTS) (Last Four Digits of Federal Tax ID: 3747); and (vi) Puerto Rico Public Buildings Authority ("PBA") (Bankruptcy Case No. 19-BK-5523-LTS) (Last Four Digits of Federal Tax ID: 3801) (Title III case numbers are listed as Bankruptcy Case numbers due to software limitations).

Pursuant to Rules 7026, 7033, and 7034 of the Federal Rules of Bankruptcy Procedure, incorporating by reference Rules 26, 33, and 34 of the Federal Rules of Civil Procedure, made applicable to contested matters through Rule 9014 of the Federal Rules of Bankruptcy Procedure, made applicable to this contested matter under Section 310 of PROMESA (48 U.S.C. § 2170), the Puerto Rico Electric Power Authority ("PREPA") by and through the Financial Oversight and Management Board for Puerto Rico (the "Oversight Board"), as PREPA's representative pursuant to section 315(b) of PROMESA, and the Puerto Rico Fiscal Agency and Financial Advisory Authority ("AAFAF") as PREPA's representative pursuant to Act 2-2017, hereby submit the following Objections and Responses of PREPA to the *Discovery Request Pursuant to Order on Motion for Protective Order, Docket No. 1995* propounded by the Creditor Unión de Trabajadores de la Industria Eléctrica y Riego Inc. ("UTIER") on May 19, 2020 (the "May 19 Requests").

PRELIMINARY STATEMENT

PREPA's Responses and Objections are based, and will be based, only upon the information that is currently available to and specifically known to PREPA as of the date hereof. PREPA reserves the right to amend or supplement the Responses and Objections at any time in light of future investigation, research, or analysis. PREPA has made reasonable efforts to respond to the UTIER's May 19 Requests as PREPA understands and interprets them. If UTIER subsequently asserts an interpretation of the May 19 Requests that differs from PREPA's, PREPA reserves the right to supplement these Responses and Objections.

GENERAL OBJECTIONS

1. PREPA objects to the May 19 Requests to the extent that they purport to impose burdens on PREPA that are inconsistent with, or not otherwise authorized by, or seek to impose obligations that exceed those imposed by, the Federal Rules of Civil Procedure, the Federal

Rules of Bankruptcy Procedure, the local rules for the United States Bankruptcy Court for the District of Puerto Rico, the Court's chambers practices and case management orders, and Judge Dein's *Order on Motion for Protective Order* (ECF No. 1995) issued on May 18, 2020 (the "May 18, 2020 Order" and collectively, the "Governing Rules"). PREPA will construe and respond to the May 19 Requests in a manner consistent with its obligations under the Governing Rules.

2. PREPA objects to the May 19 Requests to the extent that the information sought is protected from disclosure by the attorney-client privilege, the attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privileges, doctrines, or immunities protecting information from disclosure. Nothing in the Responses and Objections is intended to waive, nor shall in any way be deemed a waiver of, any of these privileges, doctrines, or immunities. Information protected by these privileges, doctrines, or immunities is not subject to disclosure, and PREPA will not provide it. PREPA intends to and does assert any and all such privileges with respect to all such information.

3. PREPA objects to the May 19 Requests as unduly burdensome to the extent that they seek information beyond what is permitted by the May 18, 2020 Order and are disproportionate to the needs of the summary proceeding on the Motion to Assume.

4. PREPA objects to the May 19 Requests to the extent they place an unreasonable burden on PREPA, including without limitation by seeking information that is equally or more readily available from public sources or that is already available to UTIER.

5. PREPA objects to the May 19 Requests to the extent that they (i) imply the existence of facts or circumstances that do not or did not exist, or (ii) state or assume legal or factual conclusions. By providing these objections and responses, PREPA does not admit any

factual or legal premise in the May 19 Requests.

6. PREPA objects to the May 19 Requests to the extent they seek information for an undefined or unstated period of time on the grounds that such requests are vague, ambiguous, overbroad, unduly burdensome and oppressive, and seek information not relevant to the issues to be resolved in this summary proceeding on the Motion to Assume nor reasonably calculated to lead to the discovery of admissible evidence.

7. PREPA objects to the May 19 Requests as vague and ambiguous to the extent the term "Contracts" used therein is undefined. PREPA will construe the term "Contracts" to refer to (i) the Amended and Restated Power Purchase and Operating Agreement, dated as of March 27, 2020, between PREPA and EcoEléctrica, L.P. ("ECO"), filed as Exhibit B-1 to the Motion to Assume, *In re Fin. Oversight & Mgmt. Bd. for P.R.*, Case No. 17-04780-LTS, ECF No. 1951-2 (D.P.R. Apr. 1, 2020) (the "ECO PPOA"); and (ii) the Amended and Restated Natural Gas Sale and Purchase Agreement, dated as of March 23, 2020 between PREPA and Gas Natural Aprovisionamientos SDG, S.A. ("Naturgy"), filed as Exhibit B-2 to the Motion to Assume, *In re Fin. Oversight & Mgmt. Bd. for P.R.*, Case No. 17-04780-LTS, ECF No. 1951-3 (D.P.R. Apr. 1, 2020) (the "Naturgy GSPA").

8. The above General Objections are incorporated into each of the following specific Responses and Objections.

OBJECTIONS TO DEFINITIONS AND RULES OF CONSTRUCTION

1. PREPA objects to the "INSTRUCTIONS and DEFINITIONS" "incorporated by reference to this request for discovery" from "the previous set of Interrogatories and Requests for Production of Documents"—as stated in UTIER's May 19 Requests—to the extent they purport to impose any obligation different from or greater than those imposed by the Governing Rules.

In responding to the May 19 Requests, and unless otherwise noted, PREPA will construe all words in accordance with their ordinary English meaning, as informed by the Governing Rules.

2. PREPA objects to the definition of the term "PREPA" as overbroad, unduly burdensome, vague, ambiguous, not proportional to the needs of the Motion to Assume insofar as it encompasses "the Puerto Rico Fiscal Agency and Financial Advisory Authority and its governing board, and any of its affiliates, parents, subsidiaries, partners, associates, divisions, agencies, instrumentalities, departments, offices, officers, directors, shareholders, members, agents, attorneys, representatives, employees, predecessors or successors in interest and/or anyone acting on PREPA's behalf." In responding to the May 19 Requests, PREPA will construe "PREPA" to mean only PREPA and its current employees, officials, and known agents reasonably likely to possess personal knowledge of information relevant to the "procedures followed by PREPA in negotiating and deciding whether to assume the Contracts"; "factors considered by PREPA in deciding whether to assume the Contracts"; and "PREPA's analysis of factors it considered in deciding whether to assume the Contracts." (Protective Order at 2–3.)

SPECIFIC OBJECTIONS AND RESPONSES

I. Documents reflecting the procedures followed by PREPA in negotiating and deciding whether to assume the Contracts.

A. Interrogatories

INTERROGATORY I.A.1:

Explain why PREPA decided to override the competitive bidding process in favor of assuming or executing the Contracts.

RESPONSE TO INTERROGATORY I.A.1:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative

process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this interrogatory as argumentative and improper on the ground that it incorrectly presumes that PREPA "decided to override the competitive bidding process." PREPA further objects to this interrogatory on the ground that it assumes a competitive bidding process was required by law. PREPA further objects to this interrogatory to the extent it calls for legal argument rather than factual information.

Subject to and without waiving its general and specific objections, PREPA responds as follows: PREPA did not "override" a competitive bidding process because no such process was required. Pursuant to Federal Rule of Civil Procedure 33(d), made applicable to this contested matter by Federal Rules of Bankruptcy Procedure 7033 and 9014, PREPA directs UTIER's attention to section I of the Justification Memorandum, dated October 29, 2019 prepared by Fernando Padilla produced at PREPA-00206 (the "Justification Memo") and to the "Request for Approval of Amended and Restated Power Purchase and Operating Agreement with EcoEléctrica and Natural Gas Sale and Purchase Agreement with Naturgy; Request for Confidential Treatment of this Letter and Accompanying Attachments" dated November 4, 2019 filed with the Puerto Rico Energy Bureau in Case No. NEPR-AP-2019-0001 on November 5, 2019 and produced at PREPA-00001 (the "PREB Approval Request") at 16-17.

INTERROGATORY I.A.2:

Explain what internal processes PREPA usually has in place for procurements that are not subject to competitive bidding and whether they were they executed for the Contracts

RESPONSE TO INTERROGATORY I.A.2:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order, particularly insofar as it seeks information regarding PREPA's general procurement processes beyond the negotiation and review of the Contracts. PREPA further objects to this interrogatory on the ground that the term "executed" is vague and ambiguous in this context. PREPA construes this interrogatory to be asking whether PREPA followed its ordinary processes for procurements that are not subject to competitive bidding when it negotiated the Contracts.

Subject to and without waiving its general and specific objections, PREPA responds as follows: To the extent this interrogatory seeks information specific to PREPA's process for approving the Contracts, PREPA directs UTIER's attention to its response to Interrogatory No. I.A.3.

INTERROGATORY I.A.3:

Describe the process of negotiation between PREPA, EcoEléctrica and Naturgy for the terms of the Contracts.

RESPONSE TO INTERROGATORY I.A.3:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as vague and overbroad. PREPA further objects to this interrogatory on the ground that it is vague and ambiguous as to whether it seeks information

regarding the overall process to negotiate the Contracts, or the process for negotiating the termination dates for the Contracts. PREPA construes this interrogatory to be seeking an overview of the process PREPA followed in negotiating the Contracts.

Subject to and without waiving its general and specific objections, PREPA responds as follows: PREPA commenced preliminary discussions with ECO and Naturgy concerning the potential amendment and extension of the ECO PPOA and the Naturgy GSPA in the fourth quarter of 2018. These discussions involved representatives of PREPA's Project Management Office, including Fernando Padilla, as well as PREPA's Executive Director, José Ortiz. PREPA's representatives were guided in these preliminary discussions by cost savings targets established in the PREPA Fiscal Plan as well as initial results of Integrated Resource Plan modeling and capacity planning analyses being performed at the time. These targets and analyses identified goals relating to generating capacity and natural gas pricing, as well as the enhanced dispatch and operating flexibility necessary to accommodate renewable generation additions, which PREPA pursued in proposing agreement terms and evaluating ECO and Naturgy responses. These considerations are summarized in the PREB Approval Request at 4.

Beginning in June 2019 and through October 2019 PREPA conducted extensive, arms-length negotiations with ECO and Naturgy, building on the parties' preliminary discussions. These negotiations were conducted via conference calls, exchange of documents and in-person meetings within and outside of Puerto Rico. Fernando Padilla and Francisco Santos of PREPA's Project Management Office led the negotiations for PREPA. Dennis Zabala, Terry Coyne and Katherine Hernandez of Sargent & Lundy advised PREPA on technical and financial matters for both transactions. King & Spalding ("K&S") provided negotiation support and legal advice on non-Puerto Rico law matters, through two teams: (i) for the ECO PPOA, Kelly Malone and

Kevin Futch, and (ii) for the Naturgy GSPA, David Lang, Kelly Malone and Evan Korngold. Mara Vázquez, now with Diaz & Vázquez, provided advice on Puerto Rico law matters. Maria DiConza and Joseph Spina of O'Melveny & Myers LLP ("O'Melveny") provided legal advice on matters relating to PREPA's Title III restructuring.

Formal negotiation of transaction-related documents began in July 2019 and continued through October 2019. PREPA conducted these negotiations with each counterparty separately, and did not share details of the negotiations with either counterparty with the other. Carlos Reyes, José Gonzalez, José Cruz and Jorge Ramirez comprised the core team from ECO. A team from Shearman & Sterling, including Fred Sosnick, Christian Rudloff and Kelsey Scribner, represented ECO. The Naturgy team consisted of L. De Adrian Belaustegui, J. Gallego Piñera and M. Suardiaz Domenech; Naturgy was not represented by external counsel.

During the negotiations, PREPA's representatives regularly consulted with its advisors concerning the consistency of proposed terms with PREPA's savings and operational flexibility targets, and those advisors analyzed the impact of the proposed terms under various scenarios on dispatch of the Generation Facilities, energy costs, fuel costs and the operation of the PREPA system as a whole. They also provided PREPA representatives with insights concerning market practice and typical approaches to pricing and delivery terms in international LNG markets. PREPA's representatives took these analyses and insights into account in presenting and responding to proposals regarding ECO and Naturgy contract terms and conditions.

The table appearing below sets out a list of key meetings relating to both transactions.

July 9-12:	PREPA / ECO meetings in San Juan to discuss ECO PPOA Term Sheet; PREPA / Naturgy meetings in San Juan to discuss Naturgy GSPA Term Sheet;

July 15-16:	PREPA / ECO meeting by conference call to discuss ECO PPOA Term Sheet;
July 18:	PREPA / ECO meeting by conference call to discuss ECO PPOA Term Sheet;
July 23:	PREPA / ECO meeting by conference call to discuss ECO PPOA Term Sheet;
	PREPA / Naturgy meeting by conference call to discuss Naturgy GSPA Term Sheet;
July 24:	PREPA / Naturgy meeting by conference call to discuss Naturgy GSPA Term Sheet;
July 31:	PREPA / Naturgy meeting by conference call to discuss Naturgy GSPA Term Sheet;
Aug 2:	PREPA / ECO meetings by conference call to discuss ECO PPOA;
Aug 7:	PREPA / ECO meetings by conference call to discuss ECO PPOA;
Aug 26-30:	PREPA / ECO meeting in NYC to discuss ECO PPOA;
Sep 3:	PREPA / Naturgy meeting by conference call to discuss Naturgy GSPA;
Sep 10-12:	PREPA / Naturgy meetings in NYC to discuss Naturgy GSPA;
Sep 17-18:	PREPA / ECO meetings in San Juan to discuss ECO PPOA;
Sep 23:	PREPA / ECO meeting by conference call to discuss ECO PPOA;
Sep 25-26:	PREPA / ECO meeting by conference call to discuss ECO PPOA;
Oct. 3:	PREPA / ECO meeting by conference call to discuss ECO PPOA;
Oct. 7:	PREPA / ECO meeting by conference call to discuss ECO PPOA;
	PREPA / Naturgy meeting by conference call to discuss Naturgy GSPA;
Oct. 8:	PREPA / ECO meeting by conference call to discuss ECO PPOA.

<u>INTERROGATORY I.A.4</u>:

Explain why PREPA decided to alter its obligations under the Contract with EcoEléctrica to assume the additional obligation of providing EcoEléctrica with LNG.

<u>RESPONSE TO INTERROGATORY I.A.4</u>:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: PREPA concluded that the additional obligation of providing ECO with natural gas was not a material change from the previous arrangement with ECO, under which ECO effectively acquired natural gas from Naturgy. Under the Naturgy GSPA, PREPA has taken on the role of fuel supplier, but under the Naturgy GSPA is effectively subcontracting this additional fuel supply obligation to Naturgy, which will deliver natural gas to the ECO Generation facility on behalf of PREPA. Moreover, PREPA determined that the removal of the Energy Payment under the ECO PPOA offset PREPA's additional expense of purchasing natural gas from Naturgy. *See* PREB Approval Request at 4-6.

<u>INTERROGATORY I.A.5</u>:

Explain why PREPA agreed to provide LNG directly to EcoEléctrica without indemnity for lost power if Naturgy fails to deliver the LNG.

<u>RESPONSE TO INTERROGATORY I.A.5</u>:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this interrogatory on the ground that it misrepresents the terms of the Contracts.

Subject to and without waiving its general and specific objections, PREPA responds as follows: Under the ECO PPOA, PREPA has agreed to supply natural gas (not LNG) directly to ECO. PREPA does not agree with the characterization that this agreement is "without indemnity for lost power if Naturgy fails to deliver the natural gas." Section 9.4 of the Naturgy GSPA fully protects PREPA in this scenario. *See also* PREB Approval Request at 9-10 & 14-15.

<u>INTERROGATORY I.A.6</u>:

Explain why PREPA agreed to the minimum take or pay obligation in Section 8 of the Naturgy GSPA.

<u>RESPONSE TO INTERROGATORY I.A.6</u>:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA

further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: The multiple scenarios under Section 6 of the Naturgy GSPA, which permit PREPA to either permanently or temporarily reduce the minimum quantities of natural gas, protect PREPA against the risk of take-or-pay liability. *See* PREB Approval Request at 13-14.

INTERROGATORY I.A.7:

Explain the reasons for the minimum and maximum contract quantities in Section 6 of the Naturgy GSPA.

RESPONSE TO INTERROGATORY I.A.7:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: The Minimum Annual Contract Quantity and Maximum Annual Contract Quantity set forth in Section 6, together with the PREPA's reduction rights described in response to Interrogatory I.A.6, above, addressed PREPA's concern with take-or-pay liability risk. *See* PREB Approval Request at 13-14.

INTERROGATORY I.A.8:

Explain why PREPA decided to change the Contract with EcoEléctrica from a power purchase and operation agreement to include a tolling agreement.

RESPONSE TO INTERROGATORY I.A.8:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: The tolling features of the ECO PPOA did not factor into PREPA's assessment in deciding whether to assume the Contracts. Naturgy indirectly controls the largest ownership interest in ECO and (through its contract rights under a Terminal Use Agreement) the importation of LNG into Southern Puerto Rico. *See* Justification Memo, Section I; *see also* PREB Approval Request at 3-4 and 16. In exchange for agreeing to the annual savings targets for the Pre-Restatement PPOA with ECO, required by the Fiscal Plan, Naturgy negotiated an extension of the supply term under the Pre-Restatement PPOA to 2032 and the right to supply natural gas to the ECO Generation Facility, during the extended supply term. By taking the gas supply function away from ECO under the ECO PPOA, this negotiated commercial position required a reformulation of the PPOA from the sale and purchase of both capacity and energy to the sale and purchase of capacity only, effectively creating a tolling arrangement.

INTERROGATORY I.A.9:

Explain why PREPA agreed to a locked-in LNG price rather than having market-based adjustments, indexes or other mechanisms to ensure that the overall price would be competitive going forward.

RESPONSE TO INTERROGATORY I.A.9:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this interrogatory on the ground that it misrepresents the terms of the Contracts.

Subject to and without waiving its general and specific objections, PREPA responds as follows: The Naturgy GSPA does not incorporate a "locked-in LNG price." Under the Naturgy GSPA, PREPA does not purchase LNG, it purchases natural gas. The contract price for natural gas fuel is based upon two components – the market price for natural gas and the transportation and a delivery adder fee. The GSPA provides for the calculation of a commodity price for each month on the basis of final settlement price for the NYMEX Henry Hub Natural Gas futures contract for the month prior to the month of delivery. The Naturgy GSPA thus includes a market-based adjustment mechanism linked to one of the world's most widely traded commodity futures contracts. This mechanism ensures that the overall price of natural gas will remain competitive going forward.

INTERROGATORY I.A.10:

Explain what process PREPA performed to seek information on recent LNG contract pricing trends. What persons or entities were consulted?

RESPONSE TO INTERROGATORY I.A.10:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: In connection with its negotiation of the Naturgy GSPA, PREPA and its advisors considered the pricing mechanism set forth in its Pre-Restatement Contract with Naturgy, the pricing mechanisms proposed in various responses to a Request for Proposals that ultimately resulted in the selection of NFEnergía as natural gas supplier to PREPA's San Juan Unit Nos. 5 & 6, the pricing mechanism established in the PREPA-NFE Fuel Sale and Purchase Agreement, publicly-available information concerning the pricing mechanisms included in LNG supply agreements executed by Cheniere Energy, Inc. affiliates, LNG trade press reports and the experience of PREPA advisors experienced in the negotiation of LNG sale and purchase agreements. As the negotiations proceeded, PREPA and its advisors periodically compared the pricing mechanism being proposed for the Naturgy GSPA with pricing provisions of which they were aware.

With respect to the transportation and delivery adder fee, the price negotiated with Naturgy for the supply of delivered natural gas was significantly lower than the adder which

PREPA secured for the pricing of natural gas delivered to San Juan Units 5 & 6 using an RFP process. Advisors PREPA consulted in connection with its negotiation of the Naturgy Contract included Sargent & Lundy, K&S, and O'Melveny.

INTERROGATORY I.A.11:

Explain PREPA's allegation that Naturgy has a *de facto* monopoly on natural gas in Puerto Rico and how this affected PREPA's ability to negotiate.

RESPONSE TO INTERROGATORY I.A.11:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this interrogatory to the extent it calls for legal argument rather than factual information.

Subject to and without waiving its general and specific objections, PREPA responds as follows: Pursuant to Federal Rule of Civil Procedure 33(d), made applicable to this contested matter by Federal Rules of Bankruptcy Procedure 7033 and 9014, PREPA directs UTIER's attention to Section I of the Justification Memo.

INTERROGATORY I.A.12:

Explain why PREPA insists on treating the Contracts as one transaction rather than two separate transactions. Did PREPA have the option to delink the Contracts? Do these Contracts depend on each other?

RESPONSE TO INTERROGATORY I.A.12:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this interrogatory as argumentative and improper on the ground that it incorrectly presumes the Contracts should be treated as "two separate transactions."

Subject to and without waiving its general and specific objections, PREPA responds as follows: Naturgy indirectly controls the largest ownership interest in ECO and (through its contract rights under the Terminal Use Agreement) the importation of LNG into Southern Puerto Rico. *See* Justification Memo, Section I; PREB Approval Request at 3-4. In exchange for agreeing to the annual savings targets for the Pre-Restatement PPOA with ECO, required by the Fiscal Plan, Naturgy negotiated an extension of the supply term under the Pre-Restatement PPOA to 2032 and the right to supply natural gas to the ECO Generation Facility, during the extended supply term, rendering the ECO PPOA co-dependent on the supply of natural gas under the Naturgy GSPA. PREPA never had the option to "disconnect" the Contracts.

INTERROGATORY I.A.13:

Explain why PREPA decided to assume or execute the Contracts until the year 2032, rather than the shorter period it negotiated with New Fortress Energy, for example.

RESPONSE TO INTERROGATORY I.A.13:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative

process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: Naturgy would only accept the gas price reductions and other changes required to achieve the cost savings required by the Fiscal Plan if PREPA extended the term of the Contracts until 2032.

INTERROGATORY I.A.14:

Explain why PREPA decided to assume or execute the Contracts, rather than explore renewable energy sources or other natural gas providers.

RESPONSE TO INTERROGATORY I.A.14:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this request on the ground that it presumes PREPA cannot simultaneously assume the Contracts and explore renewable energy options.

Subject to and without waiving its general and specific objections, PREPA responds as follows: Pursuant to Federal Rule of Civil Procedure 33(d), made applicable to this contested matter by Federal Rules of Bankruptcy Procedure 7033 and 9014, PREPA directs UTIER's attention to paragraph (1) of page VI of the report, captioned "EcoElectrica and Naturgy Contract Renegotiations", dated October 2019 and prepared by Sargent & Lundy LLC and

produced at PREPA-00230 (the "S&L Report") and Sections I and VII(3)(a) of the Justification Memo.

INTERROGATORY I.A.15:

Explain PREPA's urgency to assume or execute the Contracts.

RESPONSE TO INTERROGATORY I.A.15:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: That delay in assuming the Contracts would result in substantial lost savings for ratepayers was one of the factors PREPA considered in negotiating the Contracts. *See* S&L Report, Section 3.4; *see also* PREB Approval Request at 4-5.

B. Document Production

REQUEST FOR PRODUCTION I.B.1:

All documents and communications concerning the process of negotiations for the Contracts.

RESPONSE TO REQUEST FOR PRODUCTION I.B.1:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this Request as overbroad, unduly burdensome, and disproportionate to the needs of

the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: On May 22, 2020, PREPA produced non-privileged documents sufficient to evidence the procedures followed by PREPA in negotiating and deciding whether to assume the Contracts, the factors considered by PREPA in deciding whether to assume the Contracts, and PREPA's analysis of the factors it considered in deciding whether to assume the Contracts. These documents consist of the responsive, non-privileged materials PREPA submitted to the PREPA Governing Board, the Puerto Rico Energy Bureau ("PREB"), the Financial Oversight and Management Board for Puerto Rico (the "Oversight Board"), and the Puerto Rico Public-Private Partnerships Authority ("P3A") in connection with PREPA's requests for approval of the Contracts.

REQUEST FOR PRODUCTION I.B.2:

All documents and communications concerning the decision to assume, execute and/or amend the Contracts without the benefit of competitive bidding.

RESPONSE TO REQUEST FOR PRODUCTION I.B.2:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this Request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further

objects to this request on the ground that it assumes a competitive bidding process was required by law.

Subject to and without waiving its general and specific objections, PREPA responds as follows: On May 22, 2020 PREPA produced non-privileged documents sufficient to evidence the procedures followed by PREPA in negotiating and deciding whether to assume the Contracts, the factors considered by PREPA in deciding whether to assume the Contracts, and PREPA’s analysis of the factors it considered in deciding whether to assume the Contracts. These documents consist of the responsive, non-privileged materials PREPA submitted to the PREPA Governing Board, PREB, the Oversight Board, and P3A in connection with PREPA’s requests for approval of the Contracts.

REQUEST FOR PRODUCTION I.B.3:

All documents and communications concerning PREPA’s decision to assume, execute and/or amend the Contracts rather than explore renewable resource alternatives.

RESPONSE TO REQUEST FOR PRODUCTION I.B.3:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA’s Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this request on the ground that the phrase “renewable resource alternatives” is vague and ambiguous. PREPA further objects to this request on the ground that it presumes PREPA cannot simultaneously assume the Contracts and explore renewable energy options.

Subject to and without waiving its general and specific objections, PREPA responds as follows: On May 22, 2020 PREPA produced non-privileged documents sufficient to evidence the procedures followed by PREPA in negotiating and deciding whether to assume the Contracts, the factors considered by PREPA in deciding whether to assume the Contracts, and PREPA's analysis of the factors it considered in deciding whether to assume the Contracts. These documents consist of the responsive, non-privileged materials PREPA submitted to the PREPA Governing Board, PREB, the Oversight Board, and P3A in connection with PREPA's requests for approval of the Contracts.

REQUEST FOR PRODUCTION I.B.4:

All documents and communications concerning a competitor's interests in replacing Naturgy as PREPA's LNG supplier.

RESPONSE TO REQUEST FOR PRODUCTION I.B.4:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order, which did not allow discovery regarding competitor interest in replacing Naturgy as PREPA's LNG supplier.

REQUEST FOR PRODUCTION I.B.5:

All duly executed tolling agreements for the EcoEléctrica LNG terminal.

RESPONSE TO REQUEST FOR PRODUCTION I.B.5:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order, which did not allow discovery regarding any agreement other than the Contracts.

Subject to and without waiving its general and specific objections, PREPA responds as follows: the only "duly executed tolling agreement[]" for the ECO terminal is the ECO PPOA, which PREPA publicly filed as Exhibit B-1 to the Motion to Assume. *See In re Fin. Oversight & Mgmt. Bd. for P.R.*, No. 17-04780-LTS, ECF No. 1951-2 (D.P.R. Apr. 1, 2020).

REQUEST FOR PRODUCTION I.B.6:

All documents and communications regarding discussions or decisions to convert the Contract with EcoEléctrica from a power purchase agreement into a tolling agreement.

RESPONSE TO REQUEST FOR PRODUCTION I.B.6:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: On May 22, 2020 PREPA produced non-privileged documents sufficient to evidence the

procedures followed by PREPA in negotiating and deciding whether to assume the Contracts, the factors considered by PREPA in deciding whether to assume the Contracts, and PREPA's analysis of the factors it considered in deciding whether to assume the Contracts. These documents consist of the responsive, non-privileged materials PREPA submitted to the PREPA Governing Board, PREB, the Oversight Board, and P3A in connection with PREPA's requests for approval of the Contracts.

REQUEST FOR PRODUCTION I.B.7:

All documents and communications regarding the amount of import taxes on fuel that would be owed by Ecoeléctrica, Naturgy or any party, if the LNG was imported by EcoEléctrica or Naturgy rather than structured to appear that it was being imported by PREPA.

RESPONSE TO REQUEST FOR PRODUCTION I.B.7:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order, which did not allow discovery regarding tax implications for EcoEléctrica or Naturgy under hypothetical contract arrangements.

II. **Documents reflecting the factors considered by PREPA in deciding whether to assume the Contracts.**

A. Interrogatories

INTERROGATORY II.A.1:

Explain whether PREPA considered the effects on its ratepayers as part of the analysis conducted to assume or execute the Contracts.

RESPONSE TO INTERROGATORY II.A.1:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this request on the ground that the phrase "effects on its ratepayers" is vague and ambiguous. PREPA construes this interrogatory to seek information regarding whether PREPA considered the effect of the Contracts on rates paid by ratepayers.

Subject to and without waiving its general and specific objections, PREPA responds as follows: Annual savings realized by ratepayers was one of the primary reasons supporting PREPA's decision to enter into the Contracts. *See* S&L Report Section 3.4; Justification Memo Section I; PREB Approval Request at 4-5.

INTERROGATORY II.A.2:

Explain whether PREPA considered the earthquake damage to EcoEléctrica's facilities and its effect on that entities ability to execute its duties under the Contracts as part of the analysis conducted to assume or execute the Contracts.

RESPONSE TO INTERROGATORY II.A.2:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: PREPA performed an assessment of the Contracts prior to October 29, 2019 and the Governing Board of PREPA approved the execution and delivery of the Contracts on such date, approximately 77 days prior to the date on which an earthquake in January 2020 damaged the Costa Sur Generation Facility, causing a prolonged forced outage. Notwithstanding the foregoing timing, the terms of the Naturgy GSPA permit PREPA to reduce the minimum quantities of natural gas required for nomination as a result of a forced outage. *See* Naturgy GSPA § 6.2(b).

INTERROGATORY II.A.3:

Explain whether PREPA considered the reasonableness of the capacity payments based on EcoEléctrica's costs incurred in providing power and the amounts that it recovered in the past 20 years in capacity payments as part of the analysis conducted to assume or execute the Contracts.

RESPONSE TO INTERROGATORY II.A.3:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA

further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: PREPA did consider the reasonableness of the capacity payments to EcoEléctrica as among the costs incurred in providing power and the foreseeable costs to be incurred by both PREPA and EcoEléctrica for the duration of the agreement. This evaluation was conducted as part of the capacity payment liability risk analysis. *See* Justification Memo, Annex A (Capacity Payment Liability Risk). Costs incurred and recovered in prior periods are irrelevant to a determination as to whether a renegotiated contract is favorable to PREPA and ratepayers on a going forward basis.

INTERROGATORY II.A.4:

Explain whether PREPA considered whether Costa Sur will be repaired or retired as part of the analysis conducted to assume or execute the Contracts.

RESPONSE TO INTERROGATORY II.A.4:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: PREPA performed an assessment of the Contracts prior to October 29, 2019 and the Governing Board of PREPA approved the execution and delivery of the Contracts on such date, approximately 77 days prior to the date on which an earthquake in January 2020 damaged the

Costa Sur Generation Facility. PREPA did consider the eventual retirement of the Costa Sur Generation Facility prior to the execution and delivery of the Naturgy GSPA (*see* § 6.2(c)); *see also* PREB Approval Request at 13-14.

INTERROGATORY II.A.5:

Explain whether PREPA considered the ownership rights of the EcoEléctrica LNG Terminal as part of the analysis conducted to assume or execute the Contracts.

RESPONSE TO INTERROGATORY II.A.5:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this interrogatory to the extent it calls for legal argument rather than factual information.

Subject to and without waiving its general and specific objections, PREPA responds as follows: Pursuant to Federal Rule of Civil Procedure 33(d), made applicable to this contested matter by Federal Rules of Bankruptcy Procedure 7033 and 9014, PREPA directs UTIER's attention to Section I of the Justification Memo and paragraph (1) of page VI of the S&L Report.

INTERROGATORY II.A.6:

Explain whether PREPA considered how the Contracts affect its ability to meet the goals of Act No. 17-2019 as part of the analysis conducted to assume or execute the Contracts.

RESPONSE TO INTERROGATORY II.A.6:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative

process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this interrogatory to the extent it calls for legal argument rather than factual information.

Subject to and without waiving its general and specific objections, PREPA responds as follows: The revised Contracts provide flexibility for PREPA to support the scale-up of intermittent renewable energy sources in Puerto Rico. *See* S&L Report, Executive Summary at IV - V and Section 3.2.2.2. The revised PPOA increases the number of plant starts per year to allow for future cycling operation (*id.*, Executive Summary at V) and obligates ECO to provide a specific menu of ancillary services intended to stabilize the transmission grid. *See* ECO PPOA at § 7.6 and Appendix K. The Naturgy GSPA includes take or pay relief through exercisable macro-level options (i.e., generation from renewables exceeding15%). *See* Naturgy GSPA, § 6.2; see also PREB Approval Request at 13-14.

INTERROGATORY II.A.7:

Explain whether PREPA considered the impact that the ongoing change in the economic landscape due to the COVID-19 emergency may have on the viability of the Contracts as part of the analysis conducted to assume or execute the Contracts.

RESPONSE TO INTERROGATORY II.A.7:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this interrogatory because the term "viability" is

vague and ambiguous. PREPA construes this interrogatory to seek information regarding whether PREPA considered the impact of the COVID-19 emergency on PREPA's ability to pay the amounts required under the Contracts.

Subject to and without waiving its general and specific objections, PREPA responds as follows: The COVID-19 emergency commenced several months after PREPA completed the negotiation of, and sought approval of, the Contracts. Its decision to assume the Contracts would not be affected in any event by the impact of the COVID-19 emergency, because the Contracts remain of great value to PREPA and ratepayers. ECO and Costa Sur are among the lowest cost generators available to PREPA and are currently two of the cleanest and most reliable baseload plants on the island. Their continued availability under the terms of the Contracts is essential to PREPA's ongoing efforts to minimize the costs of the generation it requires to satisfy load and to maintain and improve system reliability. Given their relatively low cost, particularly as those costs will be reduced by implementation of the Contracts, PREPA will continue to dispatch the ECO and Costa Sur units at their maximum capacity as much as possible regardless of any negative effects resulting from the COVID-19 pandemic. PREPA anticipates no difficulty in satisfying its payment obligations under the Contracts even taking into account the impacts of the COVID-19 emergency.

INTERROGATORY II.A.8:

Explain whether PREPA considered the effect of the Contracts on its ability to adequately restructure its debts and pay its creditors as part of the analysis conducted to assume or execute the Contracts, other than seeking the FOMB's approval under the Certified Fiscal Plan.

RESPONSE TO INTERROGATORY II.A.8:

PREPA objects to this interrogatory to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this interrogatory as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this interrogatory to the extent it calls for legal argument rather than factual information.

Subject to and without waiving its general and specific objections, PREPA responds as follows: In renegotiating the Contracts, PREPA considered carefully the impact the Contracts, as renegotiated, would have on its ability to restructure its debt and pay its creditors. PREPA's approach to the renegotiation of the EcoEléctrica and Naturgy agreements was driven fundamentally by its need to achieve savings in the cost of power produced in the EcoEléctrica and Costa Sur plants, which would generate increased net revenues and, accordingly, would enhance its ability to repay creditors.

At the time it concluded the Contract negotiations and submitted the final draft Contracts to the Energy Bureau for its approval, PREPA estimated that, taken together, the Contracts would lower the cost of power from the Eco Generation Facility, already one of Puerto Rico's lowest cost generators, by approximately 1.5 cents per kWh. *See* S&L Report at Section 3.2.2 and Table 3-1. This cost reduction is beneficial to PREPA and to Puerto Rico ratepayers. The aggregate savings this reduction will yield exceed by a substantial margin the savings which FOMB established as targets from the renegotiation of both of the Pre-Restatement PPOA and a PPOA with AES Puerto Rico, the other large independent power supplier to PREPA. *See* S&L Report at 3-10 – 3-11. In addition, the increased flexibility PREPA will have under the

Contracts to dispatch the ECO Generation Facility (*see* S&L Report, Executive Summary at III-IV and 3-11) will give PREPA the ability to reduce the dispatch of its more expensive, inefficient generators, resulting in fuel cost savings that put PREPA in an improved position to stabilize its rates and repay creditors.

III. Documents reflecting PREPA's analysis of the factors it considered in deciding whether to assume the Contracts.

A. Document Production

REQUEST FOR PRODUCTION III.A.1:

All documents and communications concerning the impact of the decision to assume or execute the Contracts on PREPA's ratepayers.

RESPONSE TO REQUEST FOR PRODUCTION III.A.1:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order, which did not allow discovery into the impact of the Contracts on PREPA's ratepayers. PREPA further objects to this request on the ground that the phrase "impact . . . on PREPA's ratepayers" is vague and ambiguous. PREPA construes this request to seek documents regarding the impact of the Contracts on the rates paid by PREPA's ratepayers.

Subject to and without waiving its general and specific objections, PREPA responds as follows: On May 22, 2020 PREPA produced non-privileged documents sufficient to evidence the procedures followed by PREPA in negotiating and deciding whether to assume the Contracts, the

factors considered by PREPA in deciding whether to assume the Contracts, and PREPA's analysis of the factors it considered in deciding whether to assume the Contracts. These documents consist of the responsive, non-privileged materials PREPA submitted to the PREPA Governing Board, PREB, the Oversight Board, and P3A in connection with PREPA's requests for approval of the Contracts.

REQUEST FOR PRODUCTION III.A.2:

All documents and communications within PREPA related to Ecoeléctrica's operation after the January 7, 2020 earthquake and its impact on the decision to assume or execute the Contracts.

RESPONSE TO REQUEST FOR PRODUCTION III.A.2:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order, which did not allow discovery into EcoEléctrica's operation after the January 7, 2020 earthquake.

Subject to and without waiving its general and specific objections, PREPA responds as follows: On May 22, 2020 PREPA produced non-privileged documents sufficient to evidence the procedures followed by PREPA in negotiating and deciding whether to assume the Contracts, the factors considered by PREPA in deciding whether to assume the Contracts, and PREPA's analysis of the factors it considered in deciding whether to assume the Contracts. These documents consist of the responsive, non-privileged materials PREPA submitted to the PREPA

Governing Board, PREB, the Oversight Board, and P3A in connection with PREPA's requests for approval of the Contracts.

REQUEST FOR PRODUCTION III.A.3:

All documents and communications related to the data set and calculations used to determine the capacity payment in the Contract with EcoEléctrica.

RESPONSE TO REQUEST FOR PRODUCTION III.A.3:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: On May 22, 2020 PREPA produced non-privileged documents sufficient to evidence the procedures followed by PREPA in negotiating and deciding whether to assume the Contracts, the factors considered by PREPA in deciding whether to assume the Contracts, and PREPA's analysis of the factors it considered in deciding whether to assume the Contracts. These documents consist of the responsive, non-privileged materials PREPA submitted to the PREPA Governing Board, PREB, the Oversight Board, and P3A in connection with PREPA's requests for approval of the Contracts.

REQUEST FOR PRODUCTION III.A.4:

All documents and communications regarding the ownership rights of the EcoEléctrica LNG Terminal.

<u>RESPONSE TO REQUEST FOR PRODUCTION III.A.4</u>:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order, which did not allow discovery regarding the ownership of the ECO LNG Terminal.

<u>REQUEST FOR PRODUCTION III.A.5</u>:

All documents and communications concerning the impact of the decision to assume or execute the Contracts on PREPA's achievement of the goals contained in Act No. 17-2019.

<u>RESPONSE TO REQUEST FOR PRODUCTION III.A.5</u>:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order, which did not allow discovery regarding the energy policy goals.

<u>REQUEST FOR PRODUCTION III.A.6</u>:

All documents and communications concerning PREPA's decision to assume or execute the Contracts despite the ongoing COVID-19 emergency.

RESPONSE TO REQUEST FOR PRODUCTION III.A.6:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: On May 22, 2020 PREPA produced non-privileged documents sufficient to evidence the procedures followed by PREPA in negotiating and deciding whether to assume the Contracts, the factors considered by PREPA in deciding whether to assume the Contracts, and PREPA's analysis of the factors it considered in deciding whether to assume the Contracts. These documents consist of the responsive, non-privileged materials PREPA submitted to the PREPA Governing Board, PREB, the Oversight Board, and P3A in connection with PREPA's requests for approval of the Contracts.

REQUEST FOR PRODUCTION III.A.7:

All documents and communications concerning the calculation of projected savings of the Contracts.

RESPONSE TO REQUEST FOR PRODUCTION III.A.7:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the

summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: On May 22, 2020 PREPA produced non-privileged documents sufficient to evidence the procedures followed by PREPA in negotiating and deciding whether to assume the Contracts, the factors considered by PREPA in deciding whether to assume the Contracts, and PREPA's analysis of the factors it considered in deciding whether to assume the Contracts. These documents consist of the responsive, non-privileged materials PREPA submitted to the PREPA Governing Board, PREB, the Oversight Board, and P3A in connection with PREPA's requests for approval of the Contracts.

REQUEST FOR PRODUCTION III.A.8:

All documents reflecting the data set PREPA used in the calculation of projected savings of the Contracts.

RESPONSE TO REQUEST FOR PRODUCTION III.A.8:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order.

Subject to and without waiving its general and specific objections, PREPA responds as follows: On May 22, 2020 PREPA produced non-privileged documents sufficient to evidence the procedures followed by PREPA in negotiating and deciding whether to assume the Contracts, the

factors considered by PREPA in deciding whether to assume the Contracts, and PREPA's analysis of the factors it considered in deciding whether to assume the Contracts. These documents consist of the responsive, non-privileged materials PREPA submitted to the PREPA Governing Board, PREB, the Oversight Board, and P3A in connection with PREPA's requests for approval of the Contracts.

REQUEST FOR PRODUCTION III.A.9:

All documents and communications concerning PREPA's analysis regarding the economic savings, benefits and operational advantages that PREPA would have based on the decision to assume or execute the Contracts.

RESPONSE TO REQUEST FOR PRODUCTION III.A.9:

PREPA objects to this request to the extent it seeks information protected from disclosure by the attorney-client privilege, attorney work-product doctrine, the deliberative process privilege, the common interest privilege, or any other applicable privilege. PREPA further objects to this request as overbroad, unduly burdensome, and disproportionate to the needs of the summary proceeding on PREPA's Motion to Assume. PREPA further objects to this request as beyond the scope of the limited discovery allowed in the May 18, 2020 Order. PREPA further objects to this request on the ground that the phrase "the economic savings, benefits and operational advantages that PREPA would have based on the decision to assume or execute the Contracts" is vague and ambiguous. PREPA construes this request to be seeking documents regarding the economic savings, benefits and operational advantages to PREPA under the Contracts.

Subject to and without waiving its general and specific objections, PREPA responds as follows: On May 22, 2020 PREPA produced non-privileged documents sufficient to evidence the procedures followed by PREPA in negotiating and deciding whether to assume the Contracts, the

factors considered by PREPA in deciding whether to assume the Contracts, and PREPA's analysis of the factors it considered in deciding whether to assume the Contracts. These documents consist of the responsive, non-privileged materials PREPA submitted to the PREPA Governing Board, PREB, the Oversight Board, and P3A in connection with PREPA's requests for approval of the Contracts.

Dated: May 23, 2020
San Juan, Puerto Rico

Respectfully submitted,

PROSKAUER ROSE LLP

/s/ Paul V. Possinger

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VERIFICATION OF INTERROGATORY RESPONSES

I, Fernando M. Padilla, on behalf of the Puerto Rico Electric Power Authority ("PREPA"), hereby state that the factual averments set forth in the responses to the interrogatories set forth in *PREPA's Responses and Objections to UTIER's Discovery Request Pursuant to Order on Motion for Protective Order Docket No. 1995* are true and correct to the best of my knowledge, information, and belief.

I declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Executed on this 23rd day of May, 2020, in San Juan, Puerto Rico.

____

Fernando M. Padilla
Administrator
Program Management Office of Restructuring and Fiscal Affairs for
the Puerto Rico Electric Power Authority